minnesota power
AN ALLETE COMPANY

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November 22, 2017

VIA ELECTRONIC FILING

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: Minnesota Power's Exceptions and Requested Clarifications
In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota
MPUC Docket No. E015/GR-16-664; OAH Docket No. 5-2500-34078

Dear Mr. Wolf:

Enclosed for filing with the Minnesota Public Utilities Commission ("Commission"), please find Minnesota Power's Exceptions and Requested Clarifications to the Findings of Fact, Conclusions of Law, and Recommendations of the Administrative Law Judge ("Exceptions") in the above-referenced matter. Attached to Minnesota Power's Exceptions is Appendix A, which is the list of issues from the parties' Joint Issues Matrix, with Minnesota Power's understanding of the Administrative Law Judge's recommendations on each issue (where available). By copy of this letter, I am providing service to those on the service list on file with Commission.

Thank you for your attention to this matter. If you have any questions, please feel free to contact me.

Yours truly,

David R. Moeller

DRM/EMB:jy
Enclosure
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matt Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	MPUC Docket No. E015/GR-16-664 OAH Docket No. 5-2500-34078

MINNESOTA POWER'S EXCEPTIONS AND REQUESTED CLARIFICATIONS TO THE FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE

November 22, 2017

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I. INTRODUCTION

Minnesota Power ("Minnesota Power" or the "Company") respectfully submits the following Exceptions and Clarifications to the Administrative Law Judge's ("ALJ") Findings of Fact, Conclusions of Law, and Recommendations ("ALJ Report") in this proceeding. Pursuant to Minn. R. 7829.2700, subp. 3, and Minn. Stat. § 14.61, Minnesota Power also respectfully requests the opportunity to present oral argument before the Minnesota Public Utilities Commission ("Commission") before the Commission's deliberation and decision.

In several respects, this rate case and the issues raised throughout this proceeding present unique and important matters specific to Minnesota Power's ability to provide quality electric service in Minnesota. Minnesota Power provides retail utility electric service solely in this state, and from 2010 through 2015, Minnesota Power accounted for an average of 86 percent of ALLETE's total assets and 83 percent of ALLETE's net income.[1] The Minnesota Power business model is focused on sustaining high quality electric service to individuals, businesses, and organizations who live, work, and operate in northern Minnesota. Moreover, for generations, the Company has provided excellent jobs, offered reliable and sustainable power, and exceeded Minnesota's environmental and energy policy goals while providing economic stability and support to this region.

The continued financial integrity and stability of Minnesota Power, however, would be jeopardized if the recommendations in the ALJ Report were adopted in their entirety. Most specifically, Minnesota Power is concerned that recommendations related to the Company's return on equity ("ROE") and general recommended disallowance of recovery of actual and necessary costs of service, such as excluding the prepaid pension asset from rate base, do not

[1] Ex. 37 at 6-7 (Cutshall Direct).

adequately recognize the unique risks associated with Minnesota Power's Minnesota-centric nature.

Minnesota Power is highly dependent on constructive regulatory outcomes and a supportive regulatory environment in Minnesota. The outcome in this rate case is critical to the Company's continued economic stability and financial integrity, and therefore to enabling Minnesota Power to continue providing quality electric service and pursue important strategic goals including grid security and reliability, streamlined regulatory processes, and increased focus on renewables and conservation opportunities. Accordingly, in these Exceptions and Clarifications and throughout the entirety of this proceeding, Minnesota Power requests outcomes that would provide overall just and reasonable rates necessary to support the quality of service and financial integrity that are expected of the Company.

A. <u>Key Issues in the Proceeding</u>

Throughout this proceeding, a variety of individual issues and proposed adjustments to the Company's revenue requirement have been raised; however, as Minnesota Power explained in testimony and briefing, certain issues are of particular importance to the Company. As issues have been resolved or favorably considered in the ALJ Report, Minnesota Power believes that five key issues require particular additional Commission attention: the Company's ROE; the depreciation schedule for the Boswell Energy Center ("BEC"); recovery of the Company's prepaid pension asset; Minnesota Power's proposed Annual Rate Review Mechanism ("ARRM"); and the Energy-Intensive Trade-Exposed ("EITE") credit.

The Company's ROE is a central financial piece to Minnesota Power's success and, if set reasonably, is the key to the Company's positive relationships with its investors and credit rating agencies. The ALJ's report appears to recommend the Minnesota Department of Commerce,

Division of Energy Resources' ("Department") methodology and use of the mean number within the Department's range, albeit adjusting for errors, but does not provide a specific ROE outcome. Minnesota Power has indicated in compliance that it understands this recommendation to be approximately 8.70 percent, or the mean of the Department's recommended range, as it is not able to calculate a different number without additional direction because this number is not based on numbers or models the Company supports or utilizes in the same way.

However, the ROE espoused by the Department and the Minnesota Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") and apparently recommended by the ALJ is based on methodologies that would place Minnesota Power's ROE more than <u>50 basis points</u> below any authorized ROE in the nation for an electric utility since 2014 (8.70 vs. the next closest ROE of 9.20 for Xcel Energy that was authorized in 2017).[2] It would be 70 basis points below the ROE this Commission set for Otter Tail Power Company ("Otter Tail") less than seven months ago, in May 2017. Consequently, the ROE selected by the ALJ will weaken an otherwise strong Minnesota utility, could lead to credit downgrades, and deter investors from seeing Minnesota Power as a good investment, to the ultimate detriment of customers. Correction of errors in the Department's analysis, combined with consideration of other important factors, would place the Company's ROE at the higher end of any reasonable range – 9.66 percent if the Department's range is used, or 10.15 percent if the Company's more reasonable modeling is utilized.

With respect to the BEC depreciation schedule, the Company is concerned about the ALJ's recommended depreciation schedules for the BEC units and reasoning to support his recommendation, as the Company's proposal has the best ability to mitigate rate increases for

[2] We note that with a 9.20 percent ROE for base rates, Xcel Energy very recently requested a 10.0 percent ROE for its Renewable Energy Standard Rider. *See Xcel Energy Renewable Energy Standard Rider*, Docket No. E002/M-17-818, PETITION at 10 (Nov. 17, 2017).

customers while supporting the Company's move toward a more renewable energy supply. Minnesota Power continues to propose separating the depreciable life of BEC from the operating life for ratemaking purposes, with the goal of mitigating rates for customers. BEC should be treated as one unit for depreciation and should have one period for cost recovery because the units share critical infrastructure making them difficult to separate, and because the entire facility has been well maintained to extend operations or supporting activities to 2050. Further, treating BEC as one unit for depreciation purposes benefits both customers and the Company, as it will create certainty with regard to recovery of the BEC investments Minnesota Power has made on behalf of customers, while reducing customers' annual costs by spreading the cost recovery associated with these units over a longer period. Minnesota Power would also be in a better position to respond to outcomes of future environmental regulations or other regulatory decisions, which may have significant impacts on the future operations of the BEC units.

In addition, the Company's prepaid pension asset reflects Minnesota Power's long-term investment in its employees above the amounts included in expense each year, and is necessary to provide them with reasonable retirement benefits in consideration of their work providing electric service to Minnesota Power customers. The substance of the pension plan has not been contested in this proceeding, and the Commission has approved the level of pension benefits provided to Minnesota Power employees in past rate proceedings. Likewise, inclusion of the prepaid pension asset in Xcel Energy's rate base was explicitly approved in its 2013 rate case (Docket No. E002/GR-13-868) and was apparently not contested in its most recent rate case (even prior to the settlement) (Docket No. E002/GR-15-826).[3] As explained in more depth

[3] *See In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (May 8, 2015); *see generally In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 12, 2017).

below, it is important for Minnesota Power to recover the costs of its prepaid pension asset because these costs are necessary for providing electric service; a certain level of pension contribution is required by law to fund pension plans; contributions to the pension plan are made by shareholders and benefit customers; and including an asset deployed to provide electric service in rate base is consistent with the applicable law and standard ratemaking treatment. These benefits are, in addition, of key importance to Minnesota Power's workers, most of whom also live in Minnesota.

With respect to the ARRM, while the Company does not agree with the ALJ's recommendation to not permit implementation of the proposed ARRM, the Company believes that directing consideration of the ARRM to a separate docket would allow for existing and additional concerns and solutions related to the ARRM to be appropriately balanced with the Company's interest in implementing the mechanism.

Finally, it is essential that a decision on the treatment of the EITE credit be determined correctly in this proceeding to ensure United States Steel Corporation's Keewatin Taconite ("Keetac") facility revenues are recorded properly in either the EITE docket or the rate case, but not both. The Company supports the ALJ's recommendation that the EITE credit should be handled through rate design in this rate case.

B. Organizational Overview of Exceptions and Clarifications

The Company appreciates the ALJ's efforts to issue a thorough report considering the number of issues presented in this case. At the same time, Minnesota Power respectfully objects to several of the ALJ's findings as not reflecting the weight of the evidence in the record and seeks clarification from the Commission on several issues that do not appear to be resolved in the ALJ Report or may require further discussion. The Company therefore organizes these Exceptions and Clarifications as follows:

- *Section II.A/Exceptions*: The Company requests that the Commission decline to adopt the ALJ's recommendations concerning the following:
    - The appropriate ROE in this proceeding;
    - The BEC life extension issue;
    - Inclusion of the Prepaid Pension Asset in rate base;
    - Implementation of the Company's proposed ARRM;
    - Recovery of storm response costs;
    - Recovery of the Company's claimed membership dues;
    - Rate design issues, including revenue apportionment, the Residential Service Charge, and the block rate design;
    - The appropriate classification and allocation of the Company's meters;
    - The proposed Green Pricing Program; and
    - The Company's proposed Grid Resilience and Innovative Demonstration ("GRID") Pilot.

- *Section II.B/Clarifications*: Minnesota Power also respectfully requests clarification regarding the ALJ's findings and recommendations concerning the following:
    - Minnesota Power's EITE credit;
    - Fuel clause adjustment issues;
    - Treatment of employee expenses; and
    - Generation operation and maintenance ("O&M") expenses.

- *Section III/Disputed Issues Not Addressed in the ALJ Report*: Upon review of the ALJ Report, it appears that certain issues that are still disputed among the parties in this proceeding were inadvertently not addressed. The Company briefly addresses these issues in Section III of these Exceptions and Clarifications. These issues include:
    - Inclusion of the Company's spot bonuses and other employee benefits in the test year;
    - Transmission revenues and expense;
    - Non-labor transmission expense;
    - Charitable contributions;
    - The Company's Retirement Savings and Stock Ownership Plan ("RSOP"); and
    - The Residential time-of-use ("TOU") rider.

  The Company requests that Minnesota Power's position on each be accepted by the Commission.

- *Section IV/Resolved Issues Not Addressed in the ALJ Report*: It also appears that certain issues that were resolved between the parties were not explicitly addressed in the ALJ Report. Minnesota Power briefly addresses the following resolved issues in Section IV, and asks that the Commission accept the parties' agreement on each:
    - Hibbard Renewable Energy Center ("HREC") extended depreciation life;
    - Large Power customer test year sales forecast for paper and pulp customers, Magnetation, and Project Mustang;

- Pension expense;
- Interest on benefits and other awards;
- Base rider cash;
- High performance awards;
- Economic development expenses;
- Conservation improvement program ("CIP") expenses;
- Market charges associated with the fuel clause adjustment;
- The Business Development Incentive ("BDI") Rider;
- The Conservation Program Adjustment ("CPA") factor on customer bills;
- The power factor adjustment threshold for General Service, Large Light and Power, and Municipal Pumping classes;
- Transparency associated with the Company's class cost of service study ("CCOSS");
- Modifications to the late payment assessment;
- The Green Pricing Tariff agreement between Minnesota Power and Wal-Mart;
- Non-residential monthly service charges; and
- Compliance items recommended by the Department.

Further, attached to these Exceptions and Clarifications as Appendix A is the list of issues from the parties' Joint Issues Matrix, with Minnesota Power's understanding of the Administrative Law Judge's recommendations on each issue (where available). Minnesota Power's more detailed support for each of the issues discussed in these Exceptions and Clarifications are set forth in the Company's testimony and briefing previously submitted into the record in this proceeding.

II. EXCEPTIONS AND CLARIFICATIONS TO ALJ REPORT

A. Exceptions

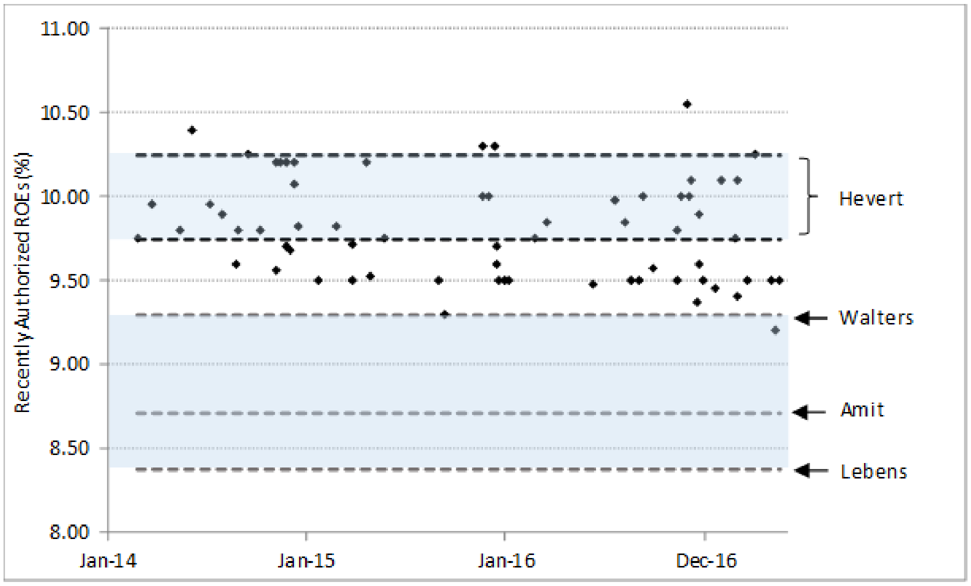
1. Return on Equity and Capital Structure

In this proceeding, Minnesota Power recommended an ROE range of 9.75 percent to 10.25 percent, and recommended an ROE of 10.15 percent within that range. Such an ROE is reasonable and based on a variety of quantitative and qualitative factors, including model results, capital market conditions, and certain risk faced by Minnesota Power, that support the reasonableness of the Company's recommended ROE. It would also place Minnesota Power

within a reasonable range of comparable, albeit less risky, utilities. Several parties to the proceeding also prepared an analysis of Minnesota Power's ROE. As of Surrebuttal, the Department recommended an ROE of 8.70 percent within a range of 7.64 percent to 9.66 percent; the OAG recommended 8.70 percent; the Large Power Intervenors ("LPI") proposed an ROE of 9.30 percent; and Wal-Mart Stores, Inc. and Sam's West, Inc. ("Wal-Mart") noted that the average ROE for electric utilities over the past four years is 9.64 percent. The ALJ ultimately appears to have recommended an ROE of 8.70 percent.

This recommendation would be damaging to Minnesota Power and irreparably affect its standing with investors and credit rating agencies and ability to provide quality electric service to customers. As explained by Company witness Mr. Robert Hevert, an ROE of 8.70 percent, as recommended by the Department and the OAG, and, as explained below, ultimately apparently recommended by the ALJ, is over 50 basis points below the lowest ROE ever authorized for a vertically integrated utility. Chart 1 from Mr. Hevert's Rebuttal Testimony, reproduced below, demonstrates that even the highest ROE recommendation by any of the parties in this proceeding (9.30 recommended by LPI) is below all but one return authorized for vertically integrated utilities since 2014, with 8.70 percent representing a significant departure from the returns available to other utilities.

Chart 1: Vertically Integrated Authorized ROEs (2014 – 2017) and Witness Recommendations[1]



Moreover, an ROE of 8.70 percent is below all authorized returns for vertically integrated utilities since at least 1980.[4] Because an ROE of 8.70 percent is so far removed from the returns available to investors in other jurisdictions, investors would likely evaluate whether their capital is best invested in Minnesota Power or another vertically integrated utility.

Nonetheless, the ALJ Report, while unclear, appears to support almost *in toto* the position of the Department with respect to the overall allowed ROE in this case despite also finding flaws in the Department's analysis. In the ALJ Report, the ALJ concluded and recommended the following:

- The Company's use of multiple models, its particular screening of companies to create a proxy list, and the subjective evaluation by the analyst is unjust and unreasonable.[5]

- The Department's proxy list should be used to run the analytical model. No additional screening or subjective analysis should be employed.[6]

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[4] As an additional note, Maui Electric Company's authorized ROE was ultimately 9.00 percent, only after a 50 basis point reduction due to the company's "inability to address certain apparent system inefficiencies." *In the Matter of the Application of Maui Elec. Co. for Approval of Rate Increases and Revised Rate Schedules and Rules*, Public Utilities Commission of the State of Hawaii Docket No. 2011-0092, DECISION AND ORDER NO. 31288 at 107 (May 31, 2013); *see* Ex. 35 at 4-5 (Hevert Rebuttal).

[5] ALJ Report at 47.

- The Discounted Cash Flow ("DCF") model should be used to determine the ROE in this proceeding. The resulting ROE should be the midpoint of the range developed by the two DCF variants, without additional subjective analysis.[7]

- The Company's proposed ROE may not be reasonable because it is based on flawed modeling and analysis.[8]

- The Company should be required to perform calculations using the two variants of the DCF model using the Department's proxy group, without additional screening or subjective analysis. The average of the range of the resulting ROE should be adopted as just and reasonable.[9]

While the ALJ Report does not state an explicit ROE recommendation, it appears that the ALJ recommends an ROE of 8.70 percent, using the Department's range with minor (unspecified) adjustments. Minnesota Power takes exception to the ALJ Report with respect to those findings and recommendations. The recommended ROE is also concerning to the Company, and should be concerning to the Commission as well for several reasons.

First, an ROE of 8.70 percent is not only 50 basis points below almost any other since 2014, but also more than 70 basis points below the ROE for Otter Tail authorized in May 2017.[10] In the Otter Tail case, the Commission approved a cost of equity of 9.41 percent. The Commission used the Department's DCF methodology as a starting point, but set the ROE above the mean results due to Otter Tail's "unique characteristics and circumstances relative to other utilities in the proxy group."[11] The Commission further explained that these factors included the following: Otter Tail's relatively smaller size; geographically diffuse customer base; the scope of the company's planned infrastructure investments; Otter Tail's performance in completing major

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[6] ALJ Report at 48.
[7] ALJ Report at 48.
[8] ALJ Report at 118.
[9] ALJ Report at 118.
[10] *See In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (May 1, 2017).
[11] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (May 1, 2017).

infrastructure projects substantially under budget; its history of providing reliable service with stable rates; and its record of effectively serving the needs of its customers.[12] As a result, Otter Tail's approved ROE fell midway between the average and higher end of comparable company ROEs to "adequately assure[] a fair and reasonable return in light of the Company's unique risk profile, substantial capital investment activity, costs of obtaining equity investment, and performance."[13] Despite the Department's request that the Commission reconsider its decision to adopt an ROE of 9.41 percent for Otter Tail,[14] the Commission was not persuaded and denied reconsideration.[15]

Similarly, Minnesota Power has established that it is relatively smaller than other utilities in its proxy group; that it has provided reliable service without a base rate increase in seven years; that it has had substantially higher capital investments and managed those investments and costs well; and that it is effectively serving customers.[16] Minnesota Power has also managed its projects well, with (for example) the recent BEC4 retrofit coming in substantially under the cap established by the Commission.[17] In addition, Minnesota Power has managed its capital structure to be in line with its request in this case,[18] has a low cost of long-term debt compared to

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[12] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (May 1, 2017).
[13] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 56 (May 1, 2017).
[14] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, REQUEST FOR RECONSIDERATION OF THE MINNESOTA DEPARTMENT OF COMMERCE (May 22, 2017).
[15] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, ORDER GRANTING RECONSIDERATION IN PART AND DENYING IN PART (July 21, 2017).
[16] Ex. 35 at 17-19 (Hevert Rebuttal); Ex. 36 at 2-6 (Hevert Surrebuttal); Ex. 32 at 11 (McMillan Direct); Ex. 33 at 11-13 (McMillan Rebuttal).
[17] Ex. 44 at 17 (Skelton Direct).
[18] Ex. 37 at 29-30 (Cutshall Direct); Ex. 38 at 25 (Cutshall Rebuttal).

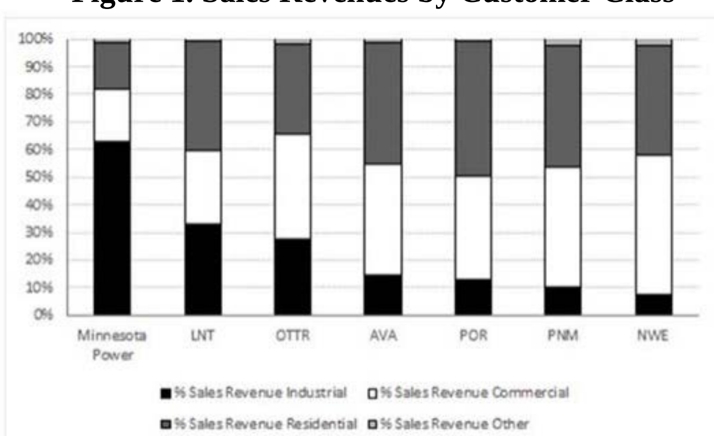
other Minnesota utilities,[19] and weathered a significant economic downturn without turning to customers for rate relief based on sales.

A key consideration here, as in the Otter Tail case, is the extent to which Minnesota Power (or ALLETE as a whole) is equally or more risky than other comparable companies. The ROE investors require is tied to the risk they are taking by investing in a particular utility. The higher the risk, the higher the required return. Therefore, both establishment of a reasonable ROE range and the selection of an ROE within that range require a realistic assessment of utility risk.

The Company presented reliable evidence in this proceeding illustrating that Minnesota Power is demonstrably and materially riskier than its peers – including Otter Tail – due largely to Minnesota Power's very high concentration of customers in very cyclical mining and paper industries. For example, the Company offered the following empirical evidence showing that the Company's risk level is higher than comparable entities:

(1) **<u>Sales Revenue by Customer Class</u>**: Minnesota Power's concentration of sales revenues to its industrial customers is almost twice the concentration of the next highest company within the Company's proxy group:[20]

Figure 1. Sales Revenues by Customer Class

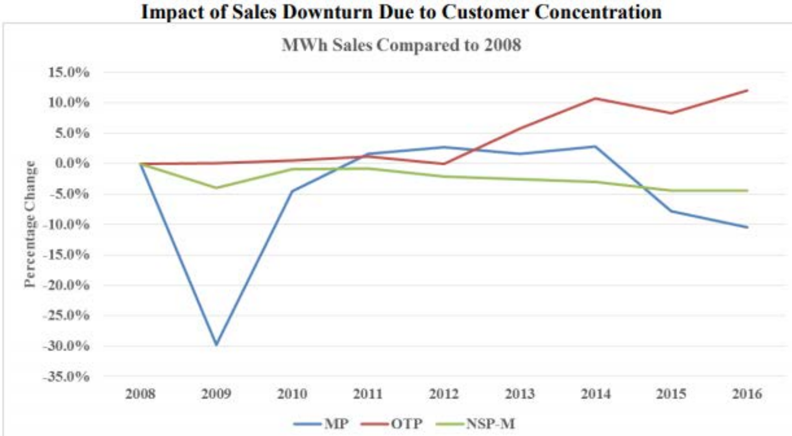


5. Source: SNL Financial

[19] Ex. 37 at 34, Table 9 (Cutshall Direct); Ex. 38 at 21 (Cutshall Rebuttal).
[20] Ex. 34 at 8 (Hevert Direct).

(2) **<u>Impact of Sales Downturn Due to Customer Concentration</u>**: Because Minnesota Power is so heavily reliant on sales to a small number of large industrial customers who operate in highly cyclical taconite and paper industries, its load profile is significantly different than other Minnesota utilities that face comparable levels of competition, operate in the same Minnesota regulatory environment, and are allowed the same cost recovery riders. As illustrated below, when compared to two neighboring Minnesota electric utilities – Northern States Power Company-Minnesota and Otter Tail – Minnesota Power is subject to much greater volatility due to its industrial load, and thus a higher level of risk.

Figure 2.
Impact of Sales Downturn Due to Customer Concentration



(3) **<u>Betas and Standard Deviation of Returns</u>**: The Department's own schedules demonstrate that by the empirical data related to measures the Department deemed to be appropriate measures of risk (i.e., most recent Beta coefficient and stock price variability), ALLETE is the riskiest company among its peers. That being the case, it would not be appropriate to set the Company's ROE at the average. Rather, it is important to recognize Minnesota Power's relative risk, and to set the return toward the upper end of the reasonable range of ROE estimates.

Table 1. Equity Risk Measures

	SIC CODE	STOCK TICKER SYMBOL	MOST RECENT BETA	BETA RANK	STANDARD DEVIATION	STD. DEV. RANK
ALLETE INC.	**4931**	**ALE**	**0.582**	**1.0**	**0.053**	**1.0**
IDACORP Inc.	4911	IDA	0.504	2.0	0.050	5.0
Avista Corp.	4931	AVA	0.454	3.0	0.049	6.0
Northwestern Corp.	4931	NWE	0.403	4.0	0.050	4.0
Alliant Energy Corp.	4931	LNT	0.391	5.0	0.045	11.0
Portland General Electric Co.	4911	POR	0.349	6.0	0.043	16.0
El Paso Electric Co.	4911	EE	0.336	7.0	0.047	8.0
Ameren Corp.	4931	AEE	0.317	8.0	0.043	13.0
Pinnacle West Capital Corp.	4911	PNW	0.312	9.0	0.046	10.0
PNM Resources Inc.	4911	PNM	0.287	10.0	0.052	2.0
DTE Energy Co.	4931	DTE	0.276	11.0	0.041	17.0
Edison International	4911	EIX	0.222	12.0	0.051	3.0
SCANA Corp.	4931	SCG	0.217	13.0	0.043	13.0
American Electric Power Co.	4911	AEP	0.213	14.0	0.044	12.0
PG&E Corp.	4931	PCG	0.202	15.0	0.047	9.0
Xcel Energy Inc.	4931	XEL	0.122	16.0	0.043	13.0
WEC Energy Group Inc.	4931	WEC	0.095	17.0	0.049	6.0

(4) <u>FFO/Debt Thresholds Acceptable to Credit Rating Agencies</u>: ALLETE needs to maintain a higher Funds From Operation ("FFO") to Debt ratio than certain peers to avoid a credit rating downgrade, as evidenced by the fact that Standard and Poor's ("S&P") provides a more stringent FFO to Debt threshold for ALLETE of 18 percent, compared to the Company's original comparison group of 15 percent and revised comparison group of 16 percent.[21]

(5) <u>Debt Equivalents</u>: Minnesota Power has a larger portion of debt equivalents as a percentage of total capitalization than the average debt equivalents as a percentage of capitalization in the Company's original and revised comparison groups. As a result, the larger portion of debt equivalents further strains the Company's credit metrics.

Table 2.
Debt Equivalents

Debt Equivalents as Percentage of Total Capitalization Unadjusted[1]			
<u>Average</u>	2014	2015	2016
Mr. Hevert's Original Comparison Group	7.27%	8.58%	9.31%
Mr. Hevert's Revised Comparison Group	6.56%	4.66%	7.18%
Minnesota Power	9.97%	10.75%	10.52%
1) Standard and Poor's Total Capitalization Unadjusted			

The Company therefore argued that not only must the potential ROE range be reasonable, but the selected ROE should be at the high end of any reasonable range.

The ALJ appeared to recognize the importance of this risk analysis, noting that the Department's ROE analysis was flawed and highlighting the fact that some of the data relied on by the Department was older than represented.[22] In particular:

> The Department's analysis included errors, however. The data for at least some of the companies was from 2005 through 2015, not 2006 through 2016. Some of the data is older than represented. The data for one proxy, PNM Resources, does not match its 10-K, and it is unclear where the data came from. Thus, the data is not accurate. This is important because PNM Resources has the highest [coefficient of variation or "COV," a critical measure of risk] at 2.86. Giving the rest of the data the benefit of the doubt, a

[21] *See* Ex. 38 at 11 (Cutshall Rebuttal).
[22] ALJ Report at 118.

> calculation excluding PNM Resources results in a mean of 0.33, not 0.48. Thus, Applicant's risk [at 0.35] is higher than the mean, but not significantly.[23]

Importantly, the ALJ also noted that compared to the Company's COV of 0.35, "[t]he data does show that Xcel Energy, the other Minnesota company in the proxy group, has the lowest COV at 0.04. Applicant is correct when it asserts it faces greater risk than at least one Minnesota company."[24]

Furthermore, while the ALJ points to the Department's use of credit ratings, Beta, and standard deviation to create a proxy group, he failed to note that ALLETE had the highest recent Beta coefficient, highest standard deviation of price changes, and the second highest Value Line Beta coefficient within the proxy group.[25] The ALJ's analysis also fails to underscore that the Department's proxy group excluded Otter Tail – a notable exclusion that helps the Department argue the Company is no riskier than the proxy group.[26] Finally, the ALJ did not include in his report Department witness Dr. Eilon Amit's admission at hearings that several of the members of his proxy group have higher risk measures because they had negative net income, massive swings in net income (for Edison, from $1,594 million to $25 million in one year, for example), or negative rates of return in certain years.[27] These are not situations the Commission should encourage, or that warrant finding the Company to be immaterially more risky than its peers simply because it has not had negative net income in the last decade. As such, the ALJ's analysis begins to recognize the higher level of risk the Company faces, but does not fully recognize the risk levels and does not appear to incorporate them into the ROE determination in a measurable or concrete way.

[23] ALJ Report at 118.
[24] ALJ Report at 118 n.917.
[25] Ex. 35 at 15 (Hevert Rebuttal); *see* Ex. 601 at Schedule (EA-10) (Amit Direct).
[26] Ex. 35 at Rebuttal Schedule 5 (Hevert Rebuttal).
[27] Evidentiary Hearing Transcript, Volume 3 at 204-05; Ex. 606 at Schedules 5 and 6 (Amit Surrebuttal).

Moreover, with respect to the ALJ's reliance on the Department's proxy group, the screening criteria used by Department witness Dr. Amit did not properly narrow his proxy group to reflect the operations and risks of Minnesota Power because Dr. Amit failed to exclude companies with DCF results outside any reasonable range.[28] In the recent past, Department witnesses, including Dr. Amit, have screened out companies with DCF results below 8.00 percent to account for anomalous and unreasonable modeling results.[29] Had Dr. Amit included the 8.00 percent financial reasonableness test, five companies would have been excluded from his proxy group, producing a proxy group that more closely reflects the risks faced by Minnesota Power. And even where the Commission has not required application of such a screen, it has not accepted the Department's recent ultra-low recommendations for electric utilities – such as the Department's 8.98 percent ROE recommendation for Otter Tail.[30]

The ALJ's report appears to recommend the Department's methodology and use of the mean number within the Department's range, albeit adjusting for errors, but does not provide a specific ROE outcome. Minnesota Power has indicated in compliance that it understands this recommendation to be approximately 8.70 percent, or the mean of the Department's recommended range without further adjustment. The Company is not able to calculate a

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[28] Likewise, the OAG argued its recommendation, which was perhaps coincidentally the exact same as the Department's, was reasonable because it was the same as the Department's recommendation. OAG Initial Brief at 86 (eDockets Document ID No. 20179-135457-02). Each therefore relies heavily and exclusively on its own modeling results and criticizes that the recommendations of the Company's witness are rarely accepted outright by the Commission. In making this argument, both parties ignore that the OAG's models have historically been far below acceptable ranges of reasonable ROE outcomes in Minnesota, and that the Department's own witness has historically applied an 8.0 percent reasonableness screen in other utility rate cases but refused to do so here when developing his range. In other words, the OAG's ROE recommendations have not become more reasonable; rather, the Department has abandoned the methodologies that have made it appear reasonable in the past.

[29] Evidentiary Hearing Transcript, Volume 3 at 234 (Amit); *see also In the Matter of the Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-13-868, DIRECT TESTIMONY OF DR. EILON AMIT at 15 (June 5, 2014); *In the Matter of the Application of N. States Power Co., d/b/a Xcel Energy, for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-12-961, DIRECT TESTIMONY OF DR. EILON AMIT at 21 (Feb. 28, 2013).

[30] Minnesota Power notes also that the Department recommended 9.06 percent for Xcel Energy in its recent electric rate case, and ultimately reached a settlement at a higher 9.20 percent.

different number without additional direction, as this number is not based on numbers or models the Company supports or utilizes in the same way. Further, the errors in the Department's analysis results in understating the Company's risk levels compared to other companies, but the ALJ both said to correct for these errors and *not* to adjust the ROE from the mean (two apparently conflicting recommendations).

The Company continues to support ROE models that take into account the flaws inherent in DCF analyses relied on by the Department, particularly in today's marketplace.[31] And even if all of the Department's modeling is generally accepted such that the Department's range is ultimately utilized, the errors in the Department's analysis go to the Company's risk levels relative to other utilities and support an ROE at the very high end of the range – which for the Department is 9.66 percent or for the Company is 10.15 percent. Even 9.66 percent is merely near the average authorized return for vertically integrated electric utilities, and only nine basis points from Minnesota Power's recommended range (9.75 percent).

Indeed, the Department's own analysis further demonstrates that the Company's ROE should be set toward the upper end of a reasonable range. As demonstrated by comparisons between the Company's empirical risk factors as compared to the proxy group, along with Exhibit EA-S-7 of Department witness Dr. Eilon Amit's Surrebuttal Testimony, it is more likely that Minnesota Power should be at the high end of the range. The probability that the Company's ROE falls between the mean of the Department's DCF (8.63 percent) and the high end of the range (9.66 percent) is 0.339, which is higher than the probability of the ROE falling between the mean (8.63 percent) and the low end of the range (7.64 percent), the probability of which is 0.329. This further supports placing the Company's ROE at the high end of a reasonable range.

[31] Ex. 34 at 29 (Hevert Direct); Ex. 35 at 23-29 (Hevert Rebuttal).

Company witness Mr. Hevert concluded, based on his updated analytical results, that a reasonable range of ROE estimates is from 9.75 percent to 10.25 percent and within that range, 10.15 percent is a reasonable and appropriate estimate of Minnesota Power's cost of equity, and Minnesota Power still asserts that this an appropriate ROE for the Company. But if the Commission agrees with the ALJ that the average of the range of the Constant Growth DCF model and the Two Growth DCF model should be used to determine the ROE in this proceeding, it is important to note that the average of the Constant Growth DCF and the Two Growth DCF mean 30-day results determined by the Company in Rebuttal Testimony was 9.17 percent – already above Dr. Amit's proposed ROE. Minnesota Power's ROE witness Mr. Robert Hevert updated his Constant Growth and Two Growth DCF analyses in Rebuttal Testimony, using the Company's proposed proxy companies (which, as discussed below, properly reflect the operations and risk of Minnesota Power, as opposed to the Department's proposed proxy group). The 30-day average mean growth rate for Mr. Hevert's updated Constant Growth DCF was 9.33 percent and the 30-day average mean growth rate for the Two Growth DCF was 9.01 percent. Moreover, the 30-day average high growth rate for Mr. Hevert's Constant Growth DCF analysis was 10.40 percent, and the 30-day average high growth rate for the Two Growth DCF analysis was 9.49 percent, with the average being 9.95 percent. Therefore, using the averages of the Constant Growth and Two Growth analyses performed by the Company, and considering the high end of that analysis, a more appropriate ROE would be closer to 9.95 percent, significantly higher than the ROE recommended by the ALJ.

With respect to the Company's capital structure, it appears that the ALJ generally agrees with both the Company and the Department, perhaps with some unspecified reserve, that

Minnesota Power's proposed capital structure is appropriate and reasonable.[32] Minnesota Power recommended a capital structure consisting of 53.81 percent common equity and 46.19 percent long-term debt.[33] The Company's proposed capital structure is consistent with its actual structure; is carefully designed to address certain risk factors and other considerations facing Minnesota Power; and is necessary for the Company to maintain its current credit ratings.

Finally, the ALJ Report does not directly address the OAG's argument that the Company should replace a portion of the equity in its capital structure with up to one percent short-term debt (or, specifically, $5 million or 0.19 percent) to bring its equity ratio closer to 50 percent at a cost of 2 percent.[34] The Company wishes to be clear that it does not support adding short-term debt to its capital structure at all, or replacing equity (rather than long-term debt) with short-term debt.

Specifically, Minnesota Power has demonstrated that it has not historically used short-term debt for any material length of time; therefore, adding short-term debt to the Company's capital structure would be artificial. Additionally, the unusual capital needs of Minnesota Power support the Company's lack of short-term debt, as the Company's industrial customer demand nomination levels are subject to periods of rapid and pronounced variability. To mitigate the effects of the demand variation, the Company must reserve liquidity through its commercial paper program or revolving credit facility, and using the commercial paper program when it is not directly needed would reduce the Company's liquidity and put negative pressure on its credit rating. Because the Company cannot afford to reduce its liquidity through regular use of short-term debt, it is not appropriate to establish a capital structure that assumes short-term debt is

[32] ALJ Report at 114-15 ("Here, Applicant's proposed equity ratio is 53.81 percent to 46.19 percent long-term debt. The cost of long-term debt is 4.52 percent. Although it is on [the] high end of the range of reasonable equity ratios, the proposed equity ratio may [be] reasonable.").
[33] Ex. 37 at 29 (Cutshall Direct); Ex. 38 at 4 (Cutshall Rebuttal).
[34] Ex. 501 at 34-35 (Lebens Direct); Ex. 504 at 13-18 (Lebens Surrebuttal).

routinely used.[35] The addition of short-term debt was also proposed in the Company's last rate proceeding (Docket No. E015/GR-09-1151). The Company demonstrated then, as it has in this proceeding, that short-term debt was not appropriate, and the Commission agreed. Changing the financing strategy now to include short-term debt, when interest rates available for long-term financing are near record lows, would add risk and would be imprudent. Minnesota Power therefore continues to support its proposed capital structure in this proceeding and respectfully requests that it be approved by this Commission.

Even with acceptance of its proposed capital structure, the ROE should not be at or anywhere near the low recommended levels (8.70 percent) that would make the Company fundamentally unable to compete for capital. Again, the ALJ did not address the likely effect of his recommended ROE on the Company's credit ratings. Specifically, credit ratings agency S&P updated its assessment of ALLETE in the spring of 2017, and increased the FFO to Debt ratio it would accept from the Company to maintain its BBB+ credit rating.[36] Rather than accepting an FFO to Debt ratio closer to 15 percent, S&P explicitly stated it is requiring the Company to maintain a ratio of at least 18.0 percent, and would prefer a ratio closer to 20 to 22 percent.[37] The Department's proposed ROE, combined with the Company's proposed capital structure, would put Minnesota Power at an FFO to Debt ratio of 17.1 percent, materially below the 18 percent FFO to Debt ratio S&P has explicitly required the Company to achieve to maintain its BBB+ credit rating.[38] In contrast, the Company's proposals would keep Minnesota Power at approximately 18.9 percent FFO to Debt ratio, which is just sustainably above the credit rating threshold. Putting the Company in a position that could result in a credit downgrade would harm

[35] Ex. 38 at 20 (Cutshall Rebuttal).
[36] *See* Ex. 38 at 6 (Cutshall Rebuttal).
[37] *See* Ex. 38 at 24 (Cutshall Rebuttal).
[38] *See* Ex. 38 at 24 (Cutshall Rebuttal).

Minnesota Power's ability to access reasonably priced capital; it would limit the number of investors willing to commit capital to the Company; and it would increase Minnesota Power's cost of capital, increasing customer rates.

Finally, it is worth noting that the customer group that pays the largest portion of Minnesota Power's rates did not recommend such an extreme ROE. LPI recommended an ROE of 9.30 percent, while Wal-Mart noted that an ROE around 9.60 percent would put Minnesota Power at approximately the average. Notably, a 9.60 percent ROE is also within the range recommended by the Department. It is simply common sense that investors will compare available ROEs among investment prospects to determine where to place their money. Accordingly, the ROEs proposed by Minnesota Power's commercial customers at least move toward more realistic outcomes than that proposed by the Department and the OAG.

For the reasons set forth above, Minnesota Power respectfully recommends modification of the ALJ's findings, conclusions, and recommendation with respect to ROE to conclude that the ROE should be set at the upper end of a reasonable range. The Company believes the appropriate level, combined with the Company's recommended capital structure, is at or nearer to 10.15 percent rather than the Department's unreasonably low mark of 8.70 percent.

2. Boswell Life Extension

In 2015, the Commission approved remaining lives for the Boswell Energy Center as follows: BEC Units 1 and 2 ("BEC1&2") – 2024; BEC Unit 3 ("BEC3") – 2034; BEC Unit 4 ("BEC4") – 2035; and the Common Facilities – 2030.[39] In this proceeding, the Company proposed to modify the depreciable life of all of the BEC units into one remaining life and

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[39] *See In the Matter of Minn. Power's 2015 Remaining Life Depreciation Petition*, Docket No. E015/D-15-711, PETITION at 10 (July 31, 2015) (proposing remaining lives); BRIEFING PAPERS at 2 (Aug. 10, 2016) (explaining that the only disputed issues pertained to facilities other than BEC).

extend that life to 2050.[40] Minnesota Power's request relates only to establishing the remaining life for cost recovery purposes, and is not meant to change the operational life or lives of any of the BEC units.[41] Rather, the Company's depreciation proposal is a rate mitigation tool that will reduce the annual costs of BEC for customers. More specifically, an extension of the BEC remaining life to 2050 will reduce the revenue requirement in this case by $22.7 million.[42] Extending the life of the BEC units will also provide stable cost recovery for the significant recent environmental upgrades at these coal-fired generation assets that face an uncertain future, thereby reducing potential volatility of future rates.[43]

BEC is Minnesota Power's largest thermal facility, with four units, all fueled by coal, and a combined capacity of over 1,000 MW.[44] Since 2007, Minnesota Power has made substantial improvements at BEC to improve its environmental performance and efficiency. These improvements include an environmental retrofit of BEC3 that was completed as of the Company's last rate case and an environmental retrofit of BEC4 that was recently completed in 2016.[45] In October 2016, the Company announced that it is closing BEC1&2 at the end of 2018 with respect to the production of energy from those units.[46]

While BEC1&2 are scheduled to be retired at the end of 2018, none of the BEC units are standalone facilities. When BEC was constructed, each of the units was built in an incremental fashion to allow shared services where appropriate and by scale as a whole facility.[47] As a result, even after BEC1&2 are no longer generating electricity, portions of their critical

[40] Ex. 40 at 15 (Minke Direct).
[41] Ex. 40 at 15 (Minke Direct).
[42] Ex. 40 at 20 (Minke Direct).
[43] Ex. 40 at 20 (Minke Direct).
[44] Ex. 40 at 16 (Minke Direct).
[45] Ex. 40 at 16 (Minke Direct).
[46] Ex. 40 at 17 (Minke Direct).
[47] Ex. 47 at 16 (Skelton Rebuttal).

electrical, water, and heating infrastructure, ancillary services, and fuel handling will continue to support the continued operation of BEC3 and BEC4.[48]

The Minnesota Chamber of Commerce ("MCC") and LPI supported Minnesota Power's BEC depreciation proposal.[49] Specifically, the MCC accurately summarized that the Company's proposal is a creative solution to minimize short-term rate impacts while enabling "Commercial, Industrial, and Residential ratepayers alike to continue strengthening the economy within Minnesota Power's service territory."[50]

The Department supported Minnesota Power's proposal as to BEC3 and BEC4, but recommended setting the economic life of BEC1&2 to 2022 because BEC3 and BEC4 had received environmental upgrades while BEC1&2 had not and the Commission directed the Company to close BEC1&2 by 2022 in the Company's most recent Integrated Resource Plan ("IRP").[51] The OAG recommended no change to the current depreciable lives for BEC, citing intergenerational inequities, FERC accounting, operational questions, and potential stranded costs.[52] The Clean Energy Organizations ("CEO") also opposed the Company's depreciation proposal, largely based on concern that this might support BEC3 and BEC4 operating longer than they otherwise would.[53]

The ALJ declined to adopt either the Company's proposed depreciation or the depreciation schedules recommended by other parties. Instead, the ALJ recommended that the depreciable lives of BEC be set as follows: BEC1&2 – 2022 and BEC3, BEC4, and the Common Facilities – 2035.[54] The ALJ reasoned that depreciation is to be based on "the estimated useful

[48] Ex. 40 at 17 (Minke Direct); Ex. 46 at 16-17 (Skelton Rebuttal).
[49] Ex. 300 at 7 (Blazar Direct); Ex. 108 at 3 (Rackers Rebuttal).
[50] Ex. 301 at 10 (Blazar Surrebuttal).
[51] Ex. 628 at 42 (Campbell Direct).
[52] Ex. 505 at 6-37 (Lee Direct).
[53] Ex. 254 at 3-14 (Varadarajan Direct).
[54] ALJ Report at 40.

life of the unit . . . in a systematic and rational manner."[55] The ALJ concluded that because the BEC units have varied useful lives, "there is not a rational basis to group them all together." The ALJ recommended 2022 for BEC1&2 because it reduces the impact on ratepayers "while not pushing the costs on another generation of ratepayers . . . after the units are no longer used and useful." The ALJ recommended BEC3, BEC4, and the Common Facilities be depreciated until 2035, the maximum approved life of any of the three units.

Minnesota Power continues to support consolidation of the BEC units into one unit and extending that life to 2050. The ALJ's analysis ignores the key facts in the record that support the Company's recommended conclusion and a conclusion that the Company believes is in the best interest of customers.

The ALJ's finding that there is no rational basis to combine the BEC units due to their varied estimated useful lives fails to take into account the evidence that the units share critical infrastructure, making it difficult to separate the useful lives of these units.[56] For instance, the electrical, water and heating infrastructure, ancillary services and fuel handling is shared amongst all of the units.[57] In addition, BEC1&2 provide compressed air, service water, and intake cooling water to the larger BEC facility, and the electrical and communication infrastructure of BEC1&2 is also closely intertwined with BEC3.[58] Thus, although BEC1&2 will no longer be generating electricity after 2018, these units will still be used to support the continued operation at BEC3 and BEC4.

[55] ALJ Report at 68 (citing Minn. R. 7825.0500, subp. 7).

[56] The ALJ also states that the Company's request should be denied as "inconsistent with prior PUC determinations, including a recent determination that 'it would not be reasonable to allow [Applicant] to depreciate an asset it no longer owns.'" ALJ Report at 68. However, the Commission's determination in that depreciation docket related to a generation asset that the Company was selling back to a customer as part of a 15-year contract. This rationale does not apply here where the Company will continue to own all of the BEC units and where portions of the to-be-retired BEC1&2 units will assist with the continued operations of BEC3 and BEC4.

[57] Ex. 40 at 18 (Minke Direct).

[58] Ex. 40 at 18 (Minke Direct).

The ALJ's recommendation seems based on the notion that the depreciation life of an asset for ratemaking purposes should precisely match the actual operational life. However, there is no legal authority that requires that these two lives be the same, and, in fact, they rarely are precisely the same, as virtually all depreciation lives incorporate a level of uncertainty about actual useful lives. In fact, none of the current depreciable lives set by the Commission for the BEC units matches their anticipated operational life. As such, the Commission is directed to "fix proper and adequate rates and methods of depreciation, amortization, or depletion in respect of utility property."[59] In establishing the service lives of utility assets, the Commission rules require straight-line depreciation (which the Company proposes) but "[n]o specific methods are prescribed by the Commission in estimating service lives and salvage value."[60] As a result, it is within the Commission's authority to set the depreciable lives of assets in any manner it determines is rational.

Not only should the lives of all of the BEC units be combined, but the depreciable life should be set to 2050 because the entire facility has been well maintained to extend operations or supporting activities to 2050. The ALJ declined to recommend a 2050 depreciable life for any of the BEC units, concluding that doing so would shift shareholder risk to ratepayers and shift costs for BEC units inequitably between current and future ratepayers.[61] The record evidence demonstrates that neither of these concerns supports rejecting the Company's proposal.

First, during this longer depreciation period, the customers experience lower rates because they do not have to return the investment to shareholders so quickly.[62] To the extent the amount paid by customers will increase in total as the net plant balance in rate base is reduced

[59] Minn. Stat. § 216B.11.
[60] Minn. R. 7825.0800.
[61] ALJ Report at 69.
[62] Ex. 42 at 14-15 (Minke Rebuttal).

over a longer period of time, this outcome relates to the time value of money and not to greater shareholder profit. The additional amount paid to shareholders is compensation for the delay in the amount of time until they see a full return on their capital investment.[63] Further, the authorized return rate—in this case the ROE—will be determined by the Commission in this and future general rate proceedings, and will not increase as a result of Minnesota Power's proposal.[64]

With regard to the ALJ's finding that the Company's proposal shifts costs of BEC units from current to future ratepayers, the Company acknowledges that this may be the case if the actual operations of these plants turn out to be different than their anticipated operational lives. However, the Company believes that these possible differences are acceptable as they help reduce costs for current customers while Minnesota Power transitions its generation supply to more renewable and renewable-supporting energy as part of the Company's Energy*Forward* strategy.[65] As such, the net benefits of this proposal outweigh the impact of potential shifts in timing of cost recovery.

Ultimately, Minnesota Power is only asking to amend the depreciation schedule; BEC1&2 are still planned for shutdown in 2018, and the Company is not requesting approval to run BEC3 and BEC4 for any period of time. Rather, the Commission will retain the authority to make such decisions in future resource plans or other proceedings. The Company's proposed depreciation schedule for the BEC units should be adopted as a reasonable way to moderate rates that strikes the appropriate balance between current and future customers while providing the Company flexibility to deal with changes in its generation portfolio.

[63] Ex. 42 at 14-15 (Minke Rebuttal).
[64] Ex. 42 at 14-15 (Minke Rebuttal).
[65] Ex. 42 at 13 (Minke Rebuttal).

3. Prepaid Pension Asset

In this proceeding, Minnesota Power proposed including a prepaid pension asset or "accumulated contributions in excess of net periodic benefit cost" in the Minnesota Jurisdictional rate base in the amount of $59,707,154. This total should be reduced by the associate tax savings of $31,890,236, resulting in a net after-tax Minnesota Jurisdictional rate base increase of $27,816,947. As recognized in the ALJ Report, the Company made "compelling arguments" for inclusion of the prepaid pension asset in rate base in this proceeding; however, the ALJ recommended against including the prepaid pension asset in rate base due in large part to those Commission decisions rejecting inclusion for other utilities.[66] Minnesota Power believes that these "compelling arguments" include the Company's several differentiations between its funding and status of its prepaid pension asset and that of other utilities for which recovery was previously disallowed.

At the outset, Minnesota Power has unquestionably demonstrated that the contributions used to fund the prepaid pension asset come from shareholders (rather than customers) and are real costs to investors. In addition, no party argued that the Company's level of cash and stock contributions to its pension fund are unreasonably high or unwarranted, and the Company has maintained this pension plan with Commission approval for decades. Thus, the only issue with respect to Minnesota Power's prepaid pension asset, in this rate case, is whether the Company should recover and earn a return on its contributions to its pension plan asset that no party has found to be unreasonable or not necessary to the provision of utility service.

Next, recognition of pension funding as a component of rate base is appropriate for several reasons: (1) it is a necessary cost of providing electric service; (2) a certain level of

[66] ALJ Report at 85. The ALJ did not address the Xcel Energy decision permitting inclusion of this asset in rate base.

pension contribution is required by law to fund pension plans; (3) contributions to the pension plan are made by the Company's shareholders and benefit customers, including by reducing pension expense; and (4) other utilities are permitted to include an asset in rate base, consistent with standard ratemaking treatment when contributions and expenses differ significantly for a particular cost. Because the regulatory compact entitles Minnesota Power to a fair return on costs incurred by shareholders to provide utility service, these costs should be included in rate base.

Minnesota Power's request for recovery of the prepaid pension asset arises because, over time, the Company has contributed far more actual cash and stock to the pension fund than the amount of expense included in rates.[67] These pension fund contributions are made to ensure adequate compensation of employees who deliver electric service to customers. And because those excess funds are locked in a fund for the benefit of employees and have not been included in rate base, Minnesota Power has lost the use of these funds without being compensated for them.

Further, the Company's contribution of these funds directly reduces the amount of pension expense that is included in rates. Simply, the prepaid amount, as it is handled today, gives the customer an interest free loan in which all of the earnings of this prepaid asset reduces the expense that the customer needs to pay, without giving any compensation to the Company for "lending" this to the customer; this interest free loan is likely to last decades. The actual funding of the prepaid pension asset earns a return that is directly and solely utilized to reduce annual pension expense for the benefit of ratepayers.[68] Compounded earnings on these contributions go

[67] *See* Ex. 38 at Schedules 8 and 11 (Cutshall Rebuttal).
[68] Ex. 37 at 66-70 (Cutshall Direct).

even further to reduce pension expense.[69] If at some time the pension declines to the point where the pension asset becomes a liability, this, too, would be included in rate base and thereby decrease it.

Nonetheless, the ALJ recommended that the prepaid pension asset not be included in the test year rate base due to the Commission's decisions in previous rate cases and because it is "impractical" to attribute specific sources for the changes in value to such an asset.[70] Though the ALJ acknowledged that Minnesota Power made "some compelling arguments for including the prepaid pension asset in its rate-base," the ALJ ultimately determined that it is not clear whether changes in value included in the asset originated from shareholder dollars, marketplace returns, or changes in actuarial accounting.

For several reasons, Minnesota Power takes exception to the ALJ's determination that it is not reasonable for the Company to recover its prepaid pension asset in rate base. First, the ALJ's reliance on Commission precedent could arguably weigh in favor of the Company's position. The Commission has recently and expressly, with a deciding order point, granted at least one similar proposal to Xcel Energy in the Commission's May 8, 2015, Findings of Fact, Conclusions, and Order in Docket No. E002/GR-13-868, and the issue was apparently not contested in Xcel Energy's 2015 rate case (even before the settlement). Minnesota Power recognizes that the Commission has also rejected proposals in Minnesota Energy Resources Corporation ("MERC") and Otter Tail rate cases to include a prepaid pension asset in rate base. The Commission noted in MERC's rate case that the prepaid pension asset issue was not contested in Xcel Energy's rate case, while it was contested in MERC's. However, there has been no argument that Xcel Energy's prepaid pension asset itself was materially different than

[69] Ex. 37 at 66-70 (Cutshall Direct).
[70] ALJ Report at 86.

Minnesota Power's. Thus, this divergence in Commission decisions appears to depend largely on the nature and extent of the arguments made against inclusion of the asset in rate base.

In this case, the evidence illustrates that the Department's arguments against including the prepaid pension asset in rate base[71] fundamentally misunderstand the prepaid pension asset. It is first important to be clear that the shareholder contributions to the prepaid pension fund and the amount of the asset the Company is seeking to include in rate base were independently confirmed in the record through submissions by Minnesota Power's actuary, Mercer, and its independent auditor, PricewaterhouseCoopers.[72] No party to this proceeding has contested the value of the pension plan itself. Nor has any party argued against the need for contributions to compensate employees, or to comply with federal law. In particular, ERISA and IRC establish minimum funding requirements for defined benefit pension plans. Although there is no requirement that a defined benefit pension plan be 100 percent funded (except upon plan termination), the Company, as plan sponsor, must make minimum annual contributions to the plan equal to the cost of annual benefit accruals plus a seven-year amortization of the unfunded liability. Nor has any party contested submission by Minnesota Power's local labor union, International Brotherhood of Electric Workers ("IBEW") Local 31, that the Company's contributions are important to Minnesota workers, as they provide highly-valued retirement security and were a key part of collective bargaining agreements.[73]

Despite the evidence presented by the Company in support of including the prepaid pension asset in rate base, the Department recommended against inclusion of the asset, as it has in some past utility rate cases before this Commission. It became evident in this proceeding,

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[71] No other party contested inclusion of this asset in rate base.
[72] *See* Ex. 38 at Schedules 8 and 11 (Cutshall Rebuttal).
[73] IBEW Public Comment (June 30, 2017), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={318E4D57-2882-4506-92EC-25E636C83E82}&documentTitle=20177-133497-01.

however, that the Department's position is premised on misunderstandings of pension accounting and reporting that demonstrate broader issues with the Department's views on prepaid pension asset rate recovery that have permeated previous Commission denials of recovery. In this rate case, Minnesota Power accurately pointed out and corrected these errors. For example, the Department incorrectly argued that the Company's recovery proposal was not in accordance with Generally Accepted Accounting Principles ("GAAP") because the Company's "pension fund as recorded on their public financial statements is a pension fund liability, which means MP is underfunded and not overfunded" and that it "is not reasonable for MP to claim, and get a return on, a supposed prepaid asset."[74] Similarly, in discovery, the Department incorrectly posited that "'accumulated contributions in excess of net periodic benefit cost' is not included anywhere in ALLETE's 2016 Annual Report; instead, the funded status is reported on the balance sheet and discussed at length in Footnote 15."[75] However, both pre-filed testimony and cross-examination at the evidentiary hearing established that the Department's arguments that there is no asset, and therefore nothing to include in rate base, overlooked half of the accounting for the prepaid pension asset.

At the evidentiary hearing and in briefing, the Company explained how to correct the Department's error so as to accurately reflect Minnesota Power's prepaid pension asset.[76] Schedule 8 to Company witness Mr. Cutshall's Rebuttal Testimony, which is PricewaterhouseCooper's confirmation that Minnesota Power's accounting and reporting regarding its prepaid pension asset is correct, is key to understanding the errors made in the Department's analysis. Mr. Cutshall's Rebuttal Schedule 8, page 3, reproduced below as Figure 3, presents a Reconciliation that shows how the various components of the prepaid

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[74] Ex. 629 at 83, 109 (Campbell Direct).
[75] Ex. 38 at Rebuttal Schedule 13 (Cutshall Rebuttal).
[76] Minnesota Power Initial Brief at 25-28.

pension asset are indeed included in the Company's 2016 Annual Report, despite the Department's claims to the contrary.

Figure 3. 2016 Annual Report

Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost
(dollars in millions)

Pension Funded Status per ALLETE, Inc.'s 2016 Form 10-K	$	(185.8)	**A**
Unrecognized Pension Costs in Accumulated Other Comprehensive Income per Allete, Inc.'s 2016 Form 10-K		250.4	**B**
Total Accumulated Contributions in Excess of Net Periodic Benefit Cost		64.6	**C**
Subtract SERP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost		(12.6)	**D**
Subtract EIP Plan Accumulated Contributions in Excess (Short) of Net Periodic Benefit Cost		(2.2)	**E**
Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost		79.4	**F**
Subtract SWL&P Pension Plan 12/31/16 Accumulated Contributions in Excess of Net Periodic Benefit Cost		6.9	**G**
Minnesota Power 12/31/16 Pension Plan Accumulated Contributions in Excess of Net Periodic Benefit Cost	$	72.5	**H**

The accompanying Notes are an integral part of this Reconciliation of ALLETE, Inc.'s 2016 Form 10-K to Minnesota Power's Accumulated Contributions in Excess of Net Periodic Benefit Cost

Line A in Figure 3 shows the funded status/pension fund liability of ($185.8 million). This funded status is the pension portion of the "Defined Benefit Pension and Other Postretirement Benefit Plans" line item on the Consolidated Balance Sheet, on which the Department relies to claim there is only a liability.[77] But it is only part of the story. The ($185.8) million funded status is found in Note 15 to the financial statements, page 123, which the Department acknowledged as being "an integral part of [the Company's financial] statements."[78] Note 15 of the 2016 ALLETE Annual Report continues on by explaining that there is an offsetting $250.4 million net loss contained in the Consolidated Balance Sheet under Accumulated Other Comprehensive Income (in this case, a loss).[79] This $250.4 million is set forth on Line B of Figure 3, above, which further explains that it represents "the total unrecognized pension costs in accumulated other comprehensive income as of December 31,

[77] Ex. 88 at 71, 123 (ALLETE 2016 Form 10-K).
[78] Evidentiary Hearing Transcript, Volume 4 at 139:15-16 (Campbell).
[79] Ex. 88 at 124 (ALLETE 2016 Form 10-K).

2016, as disclosed on page 124 of ALLETE's 2016 Form 10-K. This amount includes ALLETE's Pension Plan, Supplemental Executive Retirement Plan, and [Executive Investment Plan]."[80]

The net of Lines A and B (Line C) of the Reconciliation (Figure 3) is the Total ALLETE Accumulated Contributions in Excess of Net Periodic Benefit Cost. Because Minnesota Power is not seeking rate recovery of amounts relating to its Supplemental Executive Retirement Plan or EIP, or of amounts related to ALLETE subsidiary Superior Water, Light & Power plans, they are subtracted out in Lines D-G – establishing that the Company's 12/31/16 pension plan accumulated contribution in excess of net periodic benefit cost was, in fact, an asset of $72.5 million.[81] This 2016 year-end balance differs somewhat from the amount Minnesota Power is requesting in this proceeding, because for ratemaking, the appropriate amount is the Minnesota Jurisdictional 2017 13-month average balance, estimated at the time of filing to be $59,707,183.[82] Minnesota Power is also open to using the actual 2016 and 2017 pension contribution information.

The problem with the Department's prepaid pension asset analysis is that it did not consider the entirety of the financial information presented – for the Department's assertion that "accumulated contributions in excess of net periodic benefit cost is not included anywhere in ALLETE's 2016 Annual Report; instead, the funded status is reported on the balance sheet and discussed at length in Footnote 15" is a fundamental misunderstanding of real pension costs and ignores half of the balance sheet.[83] Though they may have subtly permeated other proceedings,

[80] Ex. 38 at Rebuttal Schedule 8, p. 4 (Cutshall Rebuttal).
[81] Ex. 38 at Rebuttal Schedule 8, p. 3-4 (Cutshall Rebuttal).
[82] Ex. 37 at 63 (Cutshall Direct).
[83] Ex. 38 at Rebuttal Schedule 13 (Cutshall Rebuttal).

these now-apparent misunderstandings of pension accounting and reporting should not impact Minnesota Power's ability to recover its prepaid pension asset in rate base.

The Department also claimed that the pension contributions are not a "physical cost," implying that the prepaid pension asset is an accounting mechanism rather than actual dollars. This is not the case. Rather, as described in the Rebuttal Testimony of Company witness Mr. Patrick Cutshall,

> The physical cost of the pension is readily described as the cash contributions made to the pension plan . . . . [F]or the period 1994 to 2016, Minnesota Power made actual Minnesota Jurisdictional contributions of $103 million, while the pension expense was $58 million and customers have only paid $14 million through rates over the same period. These contributions are real costs to investors, who should be compensated for the excess contributions . . . .[84]

Further, the Department incorrectly asserted that the prepaid pension asset is temporary and therefore fundamentally different from other kinds of assets. As explained by Mr. Cutshall,

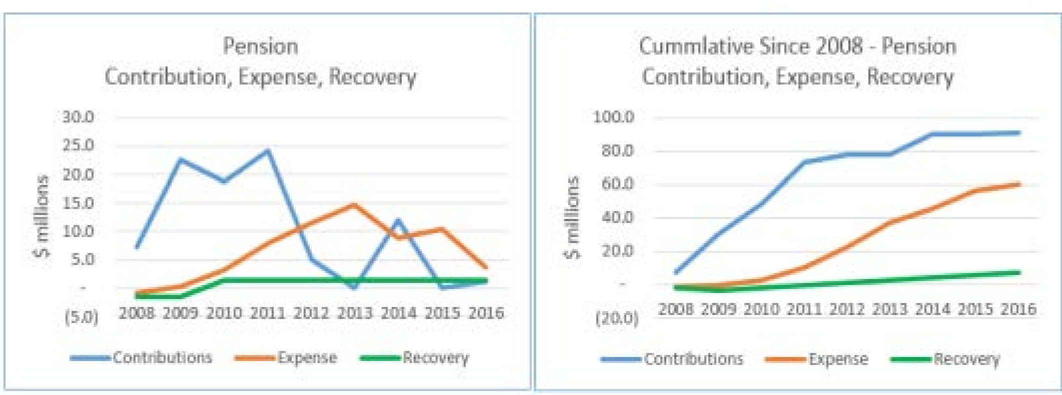
> [A]t its most basic level, all assets used for MN Jurisdictional purposes should be included in rate base; otherwise, the investors are financing an asset utilized for the delivery of electric service for the benefit of ratepayers without meeting the second half of the regulatory compact: that they will have the opportunity to earn a fair return on those reasonable investments. The fact that the prepaid pension asset is reserved to pay for utility employee pension benefits only underscores that it is dedicated to the provision of utility services.
>
> [T]here is nothing uniquely temporary about the prepaid pension asset. All items in rate base can be considered temporary, including assets such as building and equipment that depreciate over time, depending on the definition of temporary. In this case, the prepaid pension asset/liability has been around since 1987 and will be in existence until the pension fund is gone – which is no time in the foreseeable future. This is arguably as permanent as any utility asset other than perhaps unimproved land.[85]

[84] Ex. 38 at 37 (Cutshall Rebuttal).
[85] Ex. 38 at 38 (Cutshall Rebuttal).

Ultimately, the Company has never earned a return on these contributions, which are held in a fund exclusively for the purpose of providing an employment benefit to employees who provide utility service in the state of Minnesota; it should be included in rate base.

Consistent with the Department's flawed statements about the nature of the prepaid pension asset, the ALJ reasoned that it is "next to impossible" to determine whether the changes in value come from shareholder dollars, marketplace returns, or changes in actuarial accounting.[86] This misses the key issues, which are that the cash and stock contributions to the asset come solely from shareholders rather than customers, and marketplace returns only flow through to customers rather than shareholders by reducing pension expense. For example, Minnesota Power demonstrated specifically that its pension contributions from 2008 through 2016 have totaled $119.2 million total Minnesota Power ($91.2 million MN Jurisdictional). In addition, Minnesota Power has incurred pension expense totaling $78.4 million total Minnesota Power ($59.9 million MN Jurisdictional), of which the Company has only collected approximately $7.0 million on a Minnesota Jurisdictional basis through rates since 2008, as evidenced below:

Figure 4.
MN Jurisdictional Historical Pension Contributions, Expense, and Recovery



[86] ALJ Report at 85-86.

Moreover, Minnesota Power demonstrated, without contest by other parties, that there is a net benefit to customers for the 2017 test year resulting from applying expense reductions and revenue requirement from the prepaid pension asset:

Table 3. Net Benefit to Customers from Prepaid Pension Asset

All numbers in table are MN Jurisdictional

Customer benefits from prepaid pension asset:	$4,054,115
Revenue requirement for financing prepaid pension asset:	$3,643,079
Estimated 2017 net benefit prepaid benefit to customer	$411,036

Currently, the prepaid pension asset is 100 percent financed by the Company investor who is not earning a return on this fundamental cost of providing utility service.[87] Because customers pay solely for expense that is already reduced by pension fund returns, and because customers do not contribute to pension funding beyond annual expense, it is only appropriate to compensate investors for the funds that constitute the prepaid pension asset and, in turn, reduce expense.

Further, to the extent that there are changes in value, this is also true of other similar assets and liabilities included in rate base. For example, deferred tax liabilities and deferred tax assets, which are included in rate base, constantly change in value and, in some instances, the individual liability or assets will swing from a liability to an asset, or vice versa. Likewise, the prepaid pension asset is fundamentally the same as the typical rate base asset and, in fact, is so fundamentally the same that it is included in many utility companies' rate bases throughout the country and in Minnesota.[88]

Finally, excluding these Company contributions to providing a pension benefit to employees from rates is directly contrary to the requirement in Minn. Stat. § 216B.16, subd. 6, that:

[87] Ex. 38 at 34 (Cutshall Rebuttal).
[88] Ex. 38 at 38 (Cutshall Rebuttal).

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service <u>and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service</u>.[89]

There has been no dispute in this proceeding that the Company's pension plan is part of its costs of furnishing service, and no party, nor the ALJ, has contested the extent to which the Company has funded those benefits. Excluding a significant portion of the costs of the pension plan from rate recovery is, therefore, contrary to the law governing ratemaking in Minnesota.

For the above reasons, Minnesota Power continues to request inclusion of the prepaid pension asset in rate base as a whole, consistent with certain past Commission precedent. Recovery of these costs is critical to the financial health of the Company's pension fund, to this important benefit provided to Minnesota Power employees (most of whom are also Minnesota Power customers and/or Minnesota residents), and to establishing just and reasonable rates.

If, however, the Commission decides not to include Minnesota Power's Minnesota Jurisdictional $59,707,154 prepaid pension asset in rate base, ratepayers would also not receive the benefits of this asset that they have not funded. These benefits include: the associated tax savings of $31,890,236 (creating a net after-tax rate base decrease of $27,816,947) and the pension expense savings already included in the pension expense of $5,803,186. Although the ALJ was not explicit either way on this point, Company witness Mr. Cutshall illustrated in his Rebuttal Testimony that including the benefits but not the cost would be asymmetrical and fundamentally unfair.[90] Thus, the tax savings of $31,890,236 would be removed from rate base and the pension expense would be increased by $5,803,186.[91]

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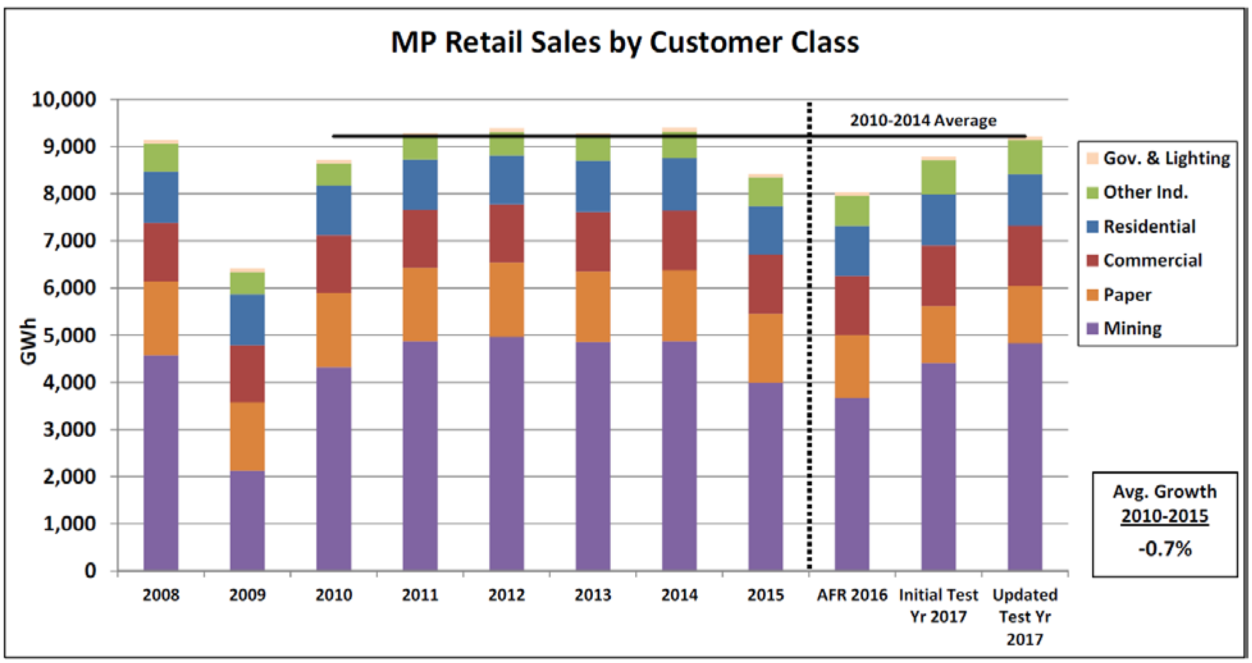
[89] Minn. Stat. § 216B.16, subd. 6 (emphasis added).
[90] Ex. 38 at 41 (Cutshall Rebuttal).
[91] *See* ALJ Compliance Filing at Schedule 3, page 5 of 6, n.28 (eDockets Document ID No. 201711-137496-02).

4. ARRM

In this case, Minnesota Power proposed a new mechanism to address significant changes in retail and resale sales between rate cases – the ARRM. This proposal derives in large part from the significant fluctuations in large power sales the Company can encounter on a year-to-year basis – both up and down (including the unanticipated restart of Keetac announced in early December 2016 and the recently-announced Blandin paper mill permanent closure of Paper Machine 5)[92] – as illustrated by the Company's actual and forecasted sales trend over the last decade, shown in Figure 5:

Figure 5. 2008 to Test Year Customer Sales By Class[93]



The ARRM is well-suited to help address these fluctuations that are unique to Minnesota Power, and is also aligned with broader efforts, such as Minnesota's e21 Initiative,[94] to

[92] Notice of Blandin Service Change (Oct. 25, 2017) (eDockets Document ID No. 201710-136825-01).
[93] Ex. 69 at Figure 1 (Pierce Supplemental Direct).
[94] *See generally* CENTER FOR ENERGY AND ENV'T, *e21 Initiative*, https://www.mncee.org/policy/e21-initiative/ (last visited Nov. 22, 2017).

streamline the regulatory process, address evolutions in the industry, and provide greater insight into the utility's business. The Company's proposed ARRM mechanism is based on a similar mechanism that has been operating in Alabama for over 30 years and was the subject of a recent, favorable Edison Electric Institute ("EEI") study.[95] The ARRM would provide for limited, potential rate adjustments between rate cases when changes in sales or other factors result in significant increases or decreases in the Company's actual ROE compared to its authorized ROE.[96] Customer protections are abundant, including a five percent cap on rate increases while providing no limit on potential rate decreases; a limit on changes in O&M expenses to a maximum of three percent annual escalation above the level allowed for the 2017 test year; a limit on an annual rate increases to three consecutive years; and expiration of the ARRM after five years.[97]

The Company proposes implementing the ARRM at the end of the year following the effective date of final rates in this rate case (2019), with the Company submitting annual compliance filings that include a CCOSS and calculation of the actual Minnesota Jurisdictional ROE for the previous year, as the basis for determining whether a rate adjustment is needed.[98] In this way, the evaluation of each filing would build off this rate case and the last annual ARRM filing, resulting in a reasonable regulatory burden of review and providing more consistent ongoing insight into the utility's revenues, expenses, investments, and cost containment.[99] Overall, the ARRM is intended to be balanced, reflecting both ups and downs within reasonable limitations, and provide stability, transparency, and improved ongoing updates and communication with the Company's regulators.

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[95] Ex. 86 at 52-53 and Schedules 14-15 (Podratz Rebuttal).
[96] Ex. 82 at 92 (Podratz Direct).
[97] Ex. 82 at 93 (Podratz Direct); Ex. 86 at 43 (Podratz Rebuttal).
[98] Ex. 82 at 92, 94-95 (Podratz Direct).
[99] Ex. 86 at 46-47 (Podratz Rebuttal).

The parties' reactions to the ARRM in this proceeding were not unexpected given that it is a new proposition for Minnesota. Parties argued that the mechanism would primarily serve shareholders (Department,[100] OAG,[101] ECC[102]) and shift risk from Minnesota Power's shareholders to ratepayers (Department,[103] ECC[104]). Parties also argued that the ARRM would reduce regulatory oversight[105]; eliminate the Company's incentive to minimize costs and maximize profits[106]; and create an unreasonable regulatory burden associated with reviewing annual ARRM filings.[107] The OAG also argued that the proposed mechanism lacks performance metrics.[108] In contrast, the MCC supports the Company's ARRM as a way to streamline implementation of the Commission's ROE decision, but encourages consideration of particular details to ensure the ARRM is just and reasonable.[109]

Ultimately, the ALJ recommends rejecting the ARRM on the grounds that "[t]he ARRM shifts business risk away from the utility and its shareholders to customers and is not consistent with any current state policy."[110] The ALJ expresses concern regarding the perceived risk of a fifteen percent increase in rates over a three-year period, and concluded that existing mechanisms (such as a multi-year rate plan) could instead alter the regulatory burden of sequential rate cases.[111]

The Company believes there are several flaws in this analysis, and that adoption or additional consideration of the ARRM – in this or another docket – is a more appropriate

[100] Ex. 601 at 68-69 (Amit Direct); Ex. 604 at 2 (Amit Rebuttal).
[101] Ex. 501 at 58-59 (Lebens Direct).
[102] Ex. 200 at 28 (Marshall Direct).
[103] Ex. 601 at 68-69 (Amit Direct).
[104] Ex. 200 at 27-28 (Marshall Direct).
[105] Ex. 604 at 2-3 (Amit Rebuttal).
[106] Ex. 601 at 68 (Amit Direct).
[107] Ex. 629 at 99-100 (Campbell Direct).
[108] Ex. 501 at 57-58 (Lebens Direct).
[109] Ex. 300 at 8 (Blazar Direct); Ex. 301 at 4 (Blazar Surrebuttal).
[110] ALJ Report at 53, ¶ 110.
[111] ALJ Report at 147.

outcome. First, with respect to the conclusion that the proposed ARRM would primarily benefit shareholders, reduce their risk, or reduce Company incentives to contain costs, it is important to be clear that the Company understands no increase is guaranteed in any given year even with the mechanism in place. Minnesota Power would continue to be required to prove the reasonableness of its costs in regular rate cases and other required Commission filings.[112] And while the parties focus on shareholder protections, the mechanism would also be invoked if the Company's earnings are above the authorized ROE. As a result, base rates could decrease between cases – largely an impossibility now – and the Company proposes a cap that would allow a larger maximum annual decrease in rates than the maximum available increase in rates.[113]

Second, the ARRM does not replace rate cases or multi-year rate plans, which do not address year-over-year volatility particularly well absent broad true-ups that begin to look like ARRM mechanisms. The ARRM mechanism is most suited to address drop-offs in revenues or capital investments that are unavoidable, while limiting customers' exposure to rate cases in which sudden declines in revenue or large-scale investments must be made up in a very short period of time. While it is true that shareholders would gain some protection in down years, customers have a much greater chance of an annual rate decrease in other years than under the current rate case regulatory structure.[114] Additionally, the ARRM would give Minnesota Power greater predictability that would better allow it to manage its costs, while allowing for limited rate adjustments within a specified ROE band.[115] A multi-year rate plan can provide the predictability of rates, but does not necessarily address mid-multi-year rate plan volatility or

[112] Ex. 86 at 46 (Podratz Rebuttal).
[113] Ex. 86 at 44 (Podratz Rebuttal).
[114] Ex. 86 at 44 (Podratz Rebuttal).
[115] Ex. 86 at 46 (Podratz Rebuttal).

ROE banding. Overall, ROE limitations in the ARRM provide greater predictability and more controls on both sides of the permitted ROE, which is to the benefit of both customers and shareholders while reducing the regulatory burden of rate cases.

Third, by allowing rate adjustments only when the earned ROE goes above or falls below a preset range, the Company's proposal ensures that Minnesota Power continues to have a financial stake and incentive to minimize costs beyond the Company's existing cost minimization incentive to support the health of the Company and reasonable rates.[116] The ROE band is simply a recognition that it is impossible to precisely pinpoint a "perfect" ROE and that actual results should be within a reasonable range. This requires the Company to manage to that reasonable range and provides assurance that neither shareholders nor customers will pay undue amounts if actual results are outside it. The incentive also exists because oversight will be more frequent – instead of the lengthy review process associated with periodic rate cases, which are ultimately most costly to customers, the ARRM would instead have a shorter, but more frequent, annual regulatory review process.[117] As such, the ARRM provides more regular insight into Minnesota Power's overall revenues, expenses, and investments.[118]

Consistent with the OAG's suggestion to include performance metrics, the Company is open to the possibility of including performance metrics tied to ratepayer and public interests.[119] The Company is also open to exploring Wal-Mart's suggestion that any rate increases that occur under the ARRM should first be applied to the approved annual cap to customer classes with relative rates of return below 1.0.[120] Minnesota Power has stated its interest in working with all parties to develop mutually-agreeable modifications to the ARRM to address the concerns raised

[116] Ex. 86 at 46 (Podratz Rebuttal).
[117] Ex. 87 at 17 (Podratz Surrebuttal).
[118] Ex. 87 at 17 (Podratz Surrebuttal).
[119] Ex. 86 at 50 (Podratz Rebuttal).
[120] Ex. 151 at 13 (Chriss Direct).

regarding the implementation of the ARRM and further the effectiveness of the mechanism.[121] The Company has been disappointed that there is little interest in these discussions, but rather an almost reflexive "no" to a mechanism that has worked well for decades elsewhere.[122] While the ARRM is newer in Minnesota, it is worth more thoughtful discussion and exploration.

To this end, the Company appreciates the discussion of MCC witness Mr. Bill Blazar, who discussed the value of streamlining lengthy regulatory processes for the benefit of customers, and explained that the MCC had hoped that a real discussion and exploration of this proposal could occur.[123] Like the Company, the MCC observed that the reaction was almost a default "no," perhaps primarily because the ARRM concept is not familiar and has the potential to alter certain regulatory review processes. Minnesota Power agrees with the Chamber that:

> To reject Minnesota Power's proposal would be "to miss an opportunity to modernize the regulatory system in a way that protects ratepayers' interests. The Commission-approved guardrails for future returns and rate increases that the ARRM would entail constitutes the very regulatory oversight that [the Department of Commerce's witness] incorrectly alleges would be missing."[124]

Consistent with these comments, Minnesota Power agrees that its ARRM should be explored further if not adopted in this proceeding, rather than rejected altogether and starting over in a future rate case or proceeding. It is appropriate (as the MCC advocates) to direct or implement "alternative steps that the parties could undertake (in this docket or others) to streamline the regulatory process for the benefit of all participants, potentially including implementation of a mechanism similar to the ARRM."[125] This outcome would also be consistent with the decision in Xcel Energy's recent electric rate case to open a separate docket

[121] Ex. 86 at 50 (Podratz Rebuttal).
[122] Ex. 86 at 52-54 (Podratz Rebuttal).
[123] Evidentiary Hearing Transcript, Volume 3 at 111:2-18 (Blazar).
[124] MCC Initial Brief at 13 (eDockets Document ID No. 20179-135461-01).
[125] MCC Initial Brief at 14 (eDockets Document ID No. 20179-135461-01).

on performance metrics.[126] The Xcel Energy docket is not far from what Minnesota Power proposes with respect to the ARRM, with the potential for additional performance measures, and would likewise align with the regulatory streamlining efforts identified earlier. In light of this docket, as well as the e21 Initiative and other, similar efforts in Minnesota, the Company respectfully submits that the ALJ Report is not correct in suggesting there is no policy basis in Minnesota for exploration or implementation of a mechanism such as the ARRM.

The Company is not in full agreement with the MCC, however, to the extent the MCC also suggests the ARRM could be modified to "increase the Company's risk" by implementing an asymmetrical cap under which the Company's earned return would have to decline materially more to trigger a rate reduction than it would increase to permit a rate increase. The Company does not support such an imbalanced result – particularly because the Company has already proposed capping rate increases at five percent while providing no limit on potential rate decreases; that changes in O&M expenses would be limited to a maximum of three percent annual escalation above the level allowed for the 2017 test year; and the ARRM would expire after five years with annual rate increases limited to three consecutive years.[127] Additional asymmetry would skew the purpose and outcomes of the ARRM, and the Company would rather have no ARRM than one that is fundamentally unfair.[128]

In sum, Minnesota Power continues to support implementation of the ARRM in the manner the Company proposes, or direction of the ARRM to a separate docket for consideration. Existing or additional concerns and solutions related to appropriately balancing interests could be addressed in that docket.

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[126] *In the Matter of a Comm'n Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Elec. Util. Operations*, Docket No. E002/CI-17-401, NOTICE OF COMMENT PERIOD (Sept. 22, 2017).
[127] Ex. 82 at 93 (Podratz Direct); Ex. 86 at 43 (Podratz Rebuttal).
[128] Ex. 86 at 44-45 (Podratz Rebuttal).

5. *Storm Restoration Budget*

In its initial filing, Minnesota Power requested that the Commission consider allowing the Company to include a budgeted amount for storm response costs, which had not previously been included in the Company's budgets.[129] In furtherance of this request, the Company included the three-year average for amounts above already-budgeted overtime amounts in RC 190 for 2014, 2015, and forecasts for 2016.[130] Because of the timing of the 2016 storm that precipitated this request and the necessary lead time before filing to incorporate amounts into the revenue requirements for the test year, this amount was identified in the Company's initial filing with specific calculations, but was not included in the initial filing's revenue requirements.[131] At that time, the Company committed to updating the request with 2016 actual expenditures and revising the revenue requirement in Rebuttal Testimony.[132]

On January 30, 2017, the Company provided the revised average, including the 2016 actual expenditures, to the parties in response to the Department's Information Request 190.[133] These updates resulted in a three-year adjusted average amount of $1.680 million (Total Company or $1.614 million MN Jurisdictional) for a storm response budget request.[134] As committed to in its initial filing, the Company also updated this information in Rebuttal Testimony and in its revenue requirements for the 2017 test year.[135]

The ALJ, in his report, reasoned that the Company's request should be denied because "the request: (1) was untimely, (2) was based on an unusual storm year; and (3) the PUC

[129] Instead, the Company has historically used overtime costs through the Company's responsibility cost center 190 ("RC 190") to restore service to customers following significant storm events. Ex. 49 at 72-73 (Fleege Direct).
[130] Ex. 49 at 73-74 and Schedule 4 (Fleege Direct).
[131] Ex. 49 at 74 (Fleege Direct).
[132] Ex. 49 at 74 (Fleege Direct).
[133] Ex. 50 at 13 and Schedule 3 (Fleege Rebuttal); Ex. 86 at 8 (Podratz Rebuttal).
[134] Ex. 50 at Schedule 3 (Fleege Rebuttal).
[135] Ex. 50 at 13 (Fleege Rebuttal); Ex. 86 at 8 (Podratz Rebuttal).

previously rejected Applicant's attempt to recovery claimed storm damage costs."[136] These will be addressed in reverse order.

Minnesota Power starts with the third rationale first, as it demonstrates that the ALJ Report unfortunately misunderstands what the Company is asking for with respect to these costs. The Commission's decision to deny Minnesota Power its request to defer and amortize the 2016 storm response expenses (Docket No. E015/M-16-648) is unrelated to the storm response request made in this rate case. The request by the Company related to the 2016 storm response expenses was a request for specific accounting treatment for a specific 2016 storm's costs, which the Commission denied – it was unrelated to the Company's request to include budgeted amounts on a going-forward basis for storm response.[137] The amortized 2016 storm response amounts included in the 2017 test year were removed from the Company's revenue requirement in Rebuttal Testimony, consistent with the Commission's Order in that Docket.[138] What the Commission decided to order with respect to the Company's request for deferred accounting of the 2016 storm response expenses is not germane to the specific budget request at issue here.

Second, the ALJ's conclusion that the request was based on an "unusual storm year" is misleading. Minnesota Power's request was based on a three-year average that, as acknowledged by the Company, does include one year of a historic storm event.[139] However, the Company used the most current information available to it to develop a three-year average for purposes of budgeting a storm response amount for the 2017 test year by using 2014, 2015, and 2016. Additionally, the Company's three-year average was intended to account for the potential

[136] ALJ Report at 41.
[137] *See In the Matter of a Petition for Approval of Deferred Accounting Treatment of Costs Related to the 2016 Storm Response and Recovery*, Docket No. E015/M-16-648, ORDER DENYING PETITION FOR DEFERRED ACCOUNTING TREATMENT (Jan. 10, 2017). The Commission decision in this Docket occurred at its December 15, 2016, agenda hearing which came *after* the Company's Initial Filing in this rate case.
[138] Ex. 86 at 7 (Podratz Rebuttal).
[139] Ex. 49 at 73-74 (Fleege Direct).

fluctuations in storm response costs over the years. Minnesota Power also provided actual cost information back to 2012 for storm response costs to show the reasonableness of the amount of its request.[140] The three-year average amount falls nearly directly between the 2014 and 2015 amounts spent on storm response, which were not of the "historic" nature of the 2016 storm.[141] The amount requested by the Company was a three-year average that *included* a historically high year, but was not *based* solely on a historically high expenditure year.

Third, this leaves the ALJ's concern that the information was untimely. However, the ALJ's conclusion that the request was untimely is simply not the fact before the Commission. The Company made the request in its initial filing, provided its initial calculation and supporting documentation, and committed to including the amounts in the revenue requirement upon filing Rebuttal Testimony. The parties requested, in discovery, updates on actual 2016 storm expenditures in January 2017 to understand the impact on the three-year average request made by the Company. At the time of making that request, the parties were aware, based on Mr. Fleege's Direct Testimony, that the amount requested was not in the 2017 test year revenue requirement calculations and that the Company intended to update that information in Rebuttal Testimony. The Company did so – no differently than it would for any other updated costs. The fact that the revenue requirement amount was not included in the total revenue requirement for the test year was, in fact, simply a benefit to customers, as it meant that these storm cost increases were also excluded from interim rates.

The ALJ, in his analysis, includes the specific statement that the request should not be denied merely because it was made following the initial filing and acknowledges that "[t]here

[140] Ex. 49 at Schedule 4 (Fleege Direct); Ex. 50 at Rebuttal Schedule 3 at 3 (Fleege Rebuttal).
[141] *See* Ex. 50 at Rebuttal Schedule 3 at 3 (Fleege Rebuttal). The average of $1.163 million and $2.016 million, the 2014 and 2015 amounts, respectively, is $1.59 million.

may be situations where such late filing is warranted."[142] The Company made the request in its initial filing, merely updating the requested amount to include the actual 2016 expenses and to update the revenue requirement. The Company should be allowed to recover just and reasonable costs associated with its response to storm events and include a storm response cost amount of $1,613,728 (MN Jurisdictional), in its 2017 test year. The ALJ's findings, conclusions, and recommendation should be modified accordingly.

6. Membership Dues

The Company proposed to include $1,240,619 (Total Company) in the 2017 test year for membership dues.[143] This amount already excluded any portions of membership dues that were related to lobbying or other non-recoverable matters.[144] This amount was adjusted downward in Rebuttal Testimony by $14,630 (Total Company or $13,592 MN Jurisdictional) to remove additional lobbying-related expenses identified by the Company during the discovery process.[145]

The OAG argued that membership dues for 11 organizations should be excluded from the 2017 test year.[146] The OAG argued that these organizations are primarily lobbying or advocacy organizations and dues, despite the fact that the Company already excluded the amounts related to lobbying as a portion of membership dues as required by the Internal Revenue Service definitions of lobbying and political expenditures.[147]

The ALJ mistakenly concluded that "Applicant provided testimony about the purposes of only three organizations."[148] Further, the ALJ incorrectly stated that the Company "did not provide the rationale for membership as to each organization or how the money spent on

[142] ALJ Report at 74.
[143] Ex. 55 at 13 (Morris Rebuttal).
[144] Ex. 55 at 13 (Morris Rebuttal).
[145] Ex. 55 at 18 (Morris Rebuttal).
[146] OAG Initial Brief at 28-29 and 34 (Sept. 12, 2017) (eDockets Document ID No. 20179-135457-02).
[147] OAG Initial Brief at 29-30 (Sept. 12, 2017) (eDockets Document ID No. 20179-135457-02).
[148] ALJ Report at 80.

membership would benefit ratepayers."[149] Based on these conclusions, the ALJ recommended that the Commission allow the Company to recover $417,946 and include that amount in the 2017 test year.[150]

However, the Company actually provided information on all 11 of the organizations that the OAG questioned in response to OAG information requests and in Rebuttal Testimony.[151] Additionally, as stated in Company witness Mr. Morris' Rebuttal Testimony, each of the 11 organizations at issue "provide valuable services and information that Minnesota Power cannot duplicate on its own."[152] The Company has appropriately and thoroughly excluded the portions of the dues for these 11 organizations that are related to lobbying activities.[153] It should therefore be allowed to include the full amount requested for membership dues, as modified in Rebuttal Testimony, in its 2017 test year. The ALJ's recommendation was based on a misapprehension of the facts in the record, and should not be adopted.

As further support that the Company should be allowed recovery of the requested amount of membership dues, it is helpful to note that Otter Tail, in its last rate case, similarly requested full recovery of its membership due expenses. The OAG challenged rate recovery of several dues paid by Otter Tail, arguing that the company did not provide record support for the portion of the dues allocated to lobbying expenses, nor did Otter Tail show that membership in the select organizations benefited ratepayers, as the OAG did in Minnesota Power's case. The Commission disagreed, finding that Otter Tail provided adequate detail demonstrating that the

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[149] ALJ Report at 81.
[150] ALJ Report at 81.
[151] Ex. 55 at Rebuttal Schedules 2-4 (Morris Rebuttal).
[152] Ex. 66 at 16 (Morris Rebuttal); Minnesota Power Initial Brief at 79-80 (Sept. 12, 2017) (eDockets Document ID No. 20179-135459-02).
[153] *See* Ex. 66 at Schedule 3 (Morris Rebuttal).

membership dues expenses included in its request for recovery are reasonable and necessary for the provision of utility service.[154] A similar determination should be made here.

7. *Rate Design*

a. <u>Revenue Apportionment</u>

In this proceeding, Minnesota Power proposed a Residential class increase of 13 to 15 percent to move the Residential class rates closer to recovering the full cost of service, while spreading the under-collection from the Residential class to the other retail classes.[155] Specifically, after the appropriate amount of Residential class increase is determined, Minnesota Power recommends an approach where the Dual Fuel increase would be set equal to the overall retail increase percent; the Lighting class would have no increase; and the remaining deviation from the CCOSS that needs to be absorbed by the other classes would be spread using a uniform percent.[156] This approach will balance the needs of the Company's various classes, while moving each class somewhat closer to its cost of service.

The ALJ disagreed with the Company's proposed revenue apportionment. In evaluating the Company's proposal, the ALJ concluded that EITE customers should receive the smallest increase in rates, if any, and the rates of all other customers should be increased equally proportionate to the cost of service for each class so that customer classes with the largest percentage revenue deficiency will see the largest increase.[157] The ALJ further concluded that the apportioned rates should increase no more than ten percent to prevent rate shock; to justly

[154] *In the Matter of the Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 49-50 (May 1, 2017).
[155] Ex. 86 at 23 (Podratz Rebuttal).
[156] Ex. 86 at 24 (Podratz Rebuttal).
[157] ALJ Report at 50.

balance the needs and expectations of all customers and the Company; and to ensure the economic engines of the region remain strong.[158]

Minnesota Power respectfully takes exception to the ALJ's recommended apportionment of the Company's revenue requirement among its customer classes. With respect to rate shock, while the Company certainly understands the importance of avoiding rate shock, it appears that the ALJ failed to consider the other factors at play that may mitigate the potential for rate shock if the Company's proposed revenue allocation were adopted. Changes in other rate components that are incorporated through cost recovery rider line items on customer bills should also be considered. These include the Renewable Resources Rider ("RRR") and potential EITE cost recovery rider rate changes. Minnesota Power implemented a reduction in rates for most customer classes (except Large Power) with its RRR factors effective January 1, 2017. In particular, this update to the RRR resulted in a decrease in Residential customer bills of 5.3 percent that is expected to continue through final rates. Further, while the Department argued that the combined impact of EITE and the Company's proposed revenue increase could result in rate shock for non-EITE customers, the Commission's orders in the EITE docket currently provide that the EITE discount will not materially impact non-EITE customers' rates. Moreover, Minnesota Power's proposed Residential class rate increase of 13 to 15 percent achieves a balance between: (1) moving all parties closer to their cost of service in the interest of fairness and to send appropriate price signals, and (2) the principle of gradualism to avoid rate shock.

It is also important to note that customers are already paying a 5.1 percent rate increase during the interim period. As noted by the Commission in the Company's 1994 rate case, "the potential for rate shock [is] reduced by customers paying higher rates during the interim rate

[158] ALJ Report at 50.

period."[159] So if the Company's final rates for the Residential customer class are higher than interim rates, it is a natural phase-in due to the timing of interim and final rate changes in the Minnesota rate case process. Accordingly, there is a lesser degree of rate shock than simply comparing previous (or "present") Residential rates to currently proposed final rates.

The Company's proposed rate increases also strike a balance between moving very close to the Residential and General Service classes' cost of service, as proposed by several parties to this proceeding, and moving even farther from the cost of service, as other parties propose.[160] This balance is illustrated in Table 4.

Table 4. Summary of Party Positions on Residential Rate Increases

ECC	6.1%
OAG	7.10%
AARP	9.29%
Department	10.00%
Company	15.0%
LPI	phase in full allocation of rate increase to residential class (up to 46.39%, depending on revenue deficiency)
MCC	33.29%
Wal-Mart	Not specified

The Company's proposed Residential class rate increase of 13 to 15 percent achieves these balances.

[159] *In the Matter of the Application of Minn. Power for Auth. to Change Its Schedule of Rates for Retail Elec. Serv. in the State of Minn.*, Docket No. E015/GR-94-001, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 68 (Nov. 22, 1994).

[160] The Department, the OAG, ECC, AARP, LPI, MCC, and Wal-Mart each addressed the Company's allocation of revenues. These parties took various positions regarding the amount of revenue that should be allocated to the Residential class versus the Large Power and Large Light and Power classes.

Minnesota Power, therefore, respectfully requests that the Commission adopt the Company's proposed revenue apportionment of a Residential class increase of 13 to 15 percent to move the Residential class rates closer to recovering the full cost of service, while spreading the under-collection from the Residential class to the other retail classes. If, however, the final authorized rate increase is less than the Company proposes, Minnesota Power believes the Residential class should receive at least a five percent final rate increase, which would simply be a continuation of the interim rate increase that the Residential class has been paying since January 2017 and would move the class rates closer to the cost of service.

b. Residential Service Charge

In this proceeding, Minnesota Power proposed to increase the Residential Service Charge from its current level of $8.00 per month to $9.00 per month.[161] This would be the first increase in Minnesota Power's customer charge since the Company's 2008 rate case. The proposed one dollar increase, or approximately 13 percent, is similar to the rate of inflation over the past seven years, since Minnesota Power's last rate case in 2009, and is also a much smaller increase than neighboring distribution cooperatives have experienced over the same seven-year time frame.[162] Further, the proposed $9.00 monthly service charge does not come remotely close to recovering the Residential customer-related service connection costs, which Minnesota Power's test year CCOSS indicated to be $26.35 per customer per month.[163] In this proceeding, the Company made efforts to ensure that the monthly service charge is not as significant as the CCOSS indicates it could be, and chose to moderate the proposed increase while also ensuring that the Company is able to collect a greater portion of the actual cost of connecting a customer to the system, metering the customer's usage, and providing customer service.

[161] Ex. 82 at 60 (Podratz Direct).
[162] Ex. 82 at 60 (Podratz Direct).
[163] Ex. 82 at 60 (Podratz Direct).

The ALJ, however, concluded that the Company failed to support its claimed Residential customer costs so that increasing the Residential Service Charge from $8.00 to $9.00 is not just and reasonable.[164] To support this conclusion, the ALJ stated that the record does not support the accuracy of Minnesota Power's basic cost of Residential service, asserting that the CCOSS is flawed and Minnesota Power has not shown how the $26.35 per month was arrived at.[165] The ALJ also found Minnesota Power's argument regarding its Residential Service Charge being significantly lower than neighboring cooperative utilities to be unconvincing.[166]

Minnesota Power respectfully disagrees with the ALJ's analysis of and conclusion regarding the Company's requested modest increase in the Residential Service Charge. First, the ALJ's assertion that the Company's CCOSS is flawed, without further analysis or explanation, appears to be based on the OAG's assertion that the customer costs found in the Company's CCOSS are flawed because the CCOSS result is based on embedded costs rather than marginal costs.[167] The monthly service charge, however, should not be based on marginal cost. For a utility to be able to collect its total cost of providing service, in general, not all rate components can be set based on marginal cost. If the goal is to send a price signal that encourages efficient consumption at a level where price equals marginal cost, it would be more important to have the price for the last increment of usage (e.g., the Residential energy rate for the highest level of consumption) be equal to marginal cost. The Commission has also found that while a rigorous calculation of marginal cost might be helpful to encourage efficiency, appropriate marginal cost calculations are not only difficult to derive in a rate case, but also conflict with the need for the utility to recover its cost of service:

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[164] ALJ Report at 50.
[165] ALJ Report at 50, 129.
[166] ALJ Report at 50.
[167] ALJ Report at 128-29.

> The Commission concurs with the ALJ that the goal of setting efficient price signals would ideally be informed by a rigorous calculation of marginal cost, and that this number can be difficult to derive from the record of a rate case. But more importantly, sending efficient price signals is merely one of the Commission's objectives. Setting the price of energy at the marginal cost of production, and setting the customer charge at the marginal cost to connect and maintain a customer, may not permit a utility to recover its cost of service.[168]

Therefore, contrary to the ALJ's conclusion, establishing a reasonable level of fixed cost recovery through the monthly service charge better serves the goal of setting appropriate price signals and encouraging conservation.

The ALJ also finds that there is uncertainty in the classification of advanced metering infrastructure ("AMI") meter costs, which the Company classifies as 100 percent customer costs.[169] He finds that based on the evidence in the record the cost of the AMI meters is more than one-third customer-related but less than 100 percent and therefore concludes that the cost of meters should be excluded from customer costs.[170]

In addition, the ALJ appears not to have understood the calculations of the revenue requirements by customer class shown on Ex. 6, Sched. E-2 at 104 (Initial Filing Vol. 4), that he references in his findings and recommendations.[171] This exhibit is a summary of output from the CCOSS that includes revenue requirements for demand, energy, and customer components for each retail rate class. The Residential class customer cost of $26.35 per month is shown in column [1], line 11 and is arrived at by dividing the annual residential Customer revenue requirements of $35,495,349 (line 3) by the annual number of bills of 1,347,029 (line 7).

[168] *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 60 (June 12, 2017).
[169] ALJ Report at 31
[170] ALJ Report at 49.
[171] ALJ Report at 32 n.287; 129 n.1012.

Minnesota Power acknowledges that the steps in this calculation could have been explained better.

Moreover, the Company continues to believe its argument that its proposed customer charge being low in comparison to customer charges of surrounding electric cooperatives supports a modest one dollar increase in the Residential Service Charge, despite the ALJ's determination to the contrary. Neighboring cooperative electric utilities providing service in northeastern Minnesota serve customers that live in areas adjacent to Minnesota Power's service territory with similar economic conditions and income levels, and these customers are paying significantly higher monthly service charges, as shown in Table 5, below:

Table 5. Cooperative Monthly Service Charges

Cooperative (headquarters and service center locations shown in parentheses)	**2009 Monthly Service Charge**	**2016 Monthly Service Charge**
Cooperative Light & Power (Two Harbors)	$16.00	$27.00
Crow Wing Power (Brainerd)	$12.00	$18.00
East Central Energy (Braham)	$16.00	$28.75
East Itasca-Mantrap (Park Rapids)	$16.50	$33.00
Lake Country Power (Grand Rapids, Virginia, and Kettle River)	$20.00	$42.00
Mille Lacs Energy Cooperative (Aitkin)	$24.00	$25.00
North Itasca Electric Cooperative (Bigfork)	$31.50	$43.00

The fact that these customers are asked to pay significantly higher service charges than Minnesota Power has proposed in this proceeding reinforces that a one dollar increase is reasonable.

Maintaining the customer service charge, as recommended by the ALJ, will result in shifting additional cost recovery to the energy rate with no movement toward reflecting the Company's actual fixed costs of providing service. The Company continues to support a relatively modest increase of $1.00 in the monthly service charge as reasonable, and would still be at the low end compared to surrounding electric co-ops who charge $18 to $43 per month.

Minnesota Power respectfully requests that this Commission agree with the Company, and approve an increase in the monthly service charge by $1.00, from $8.00 to $9.00, and find that Minnesota Power's request is reasonable and necessary to collect a greater portion of the actual cost of connecting a customer to the Company's system, metering the customer's usage, and providing customer service.

c. Block Rate Design

Minnesota Power proposed to transition from a five-block Residential energy rate structure to a two-block rate structure in this proceeding, and further agreed with the Department's recommendation to eliminate the block rate structure altogether in the Company's next rate case.[172] The Company's proposed block rate transition is demonstrated in Table 6, below:

Table 6. Residential Energy Rates

	Existing (¢/kWh)	Original Proposed (¢/kWh)	Revised Proposed (¢/kWh)
0-300 kWh	5.098	7.413	7.110
301-500 kWh	6.735	7.413	7.110
501-750 kWh	8.168	10.414	10.105
751-1000 kWh	8.445	10.414	10.105
Over 1000 kWh	8.937	10.414	10.105

The Company's current Residential rates were put in place as a pilot in Minnesota Power's 2009 retail rate case, where the Commission required the Company to adopt a five-block rate design, with "inverted block" rates that increase for higher quantities of energy usage.[173] The design was intended to reduce electric bills for those customers with high rates of

[172] Ex. 82 at 57-60 (Podratz Direct); Ex. 86 at 28-31 (Podratz Rebuttal); Ex. 87 at 9-11 (Podratz Surrebuttal).
[173] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 65-66 (Nov. 2, 2010).

consumption while also providing an incentive for conservation by those with high rates of consumption.[174] The Commission also directed Minnesota Power to evaluate the effectiveness of the pilot program on an annual basis and required the Company, in its next rate case, to recommend whether to continue the pilot Residential rate design.[175]

In conducting its annual compliance filings, the Company observed that a Minnesota Power Residential customer who uses 500 to 750 kWh per month pays less per kWh than customers of other Minnesota investor-owned utilities.[176] Further, Minnesota Power's current inverted-block rate structure causes customers to pay a higher rate (in cents per kWh) as their usage increases, while customers of other investor-owned utilities have rates that decrease as their usage increases.[177] The Company's analysis did not provide clear evidence to conclude that the five-block rate incentivizes conservation and led to lower energy consumption.[178] In fact, no party has identified evidence that this incentive is working as intended. But the Company has presented evidence in this proceeding that the structure is confusing to customers.

Despite the information presented by the Company in support of decreasing the current five-block rate structure to a two-block rate structure, the ALJ stated that Minnesota Power's "current five-block structure appears to be reducing residential electricity consumption" and concluded that the Company's proposal to eliminate the current five-block structure for a two-block structure is not just and reasonable.[179] Rather, the ALJ recommends leaving the five-block rate structure in place.

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[174] Ex. 82 at 57 (Podratz Direct).
[175] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 66 (Nov. 2, 2010).
[176] Ex. 82 at 58 (Podratz Direct).
[177] Ex. 82 at 58 (Podratz Direct).
[178] Ex. 82 at 58 (Podratz Direct).
[179] ALJ Report at 50.

Maintaining the five-block rate structure, however, has not evidenced incentivized Residential conservation or a decrease in energy consumption, as was the Commission's original goal when implementing the structure. Rather, despite the ALJ's findings to the contrary, the five-block structure presents added complexity when offering rates that are layered on top of the existing rate base structure, such as the Pilot Rider for Customer Affordability of Residential Electricity ("CARE") and the Pilot Rider for Residential TOU Service, presenting a more complicated scenario both for the Company in terms of rate design and for customers' understanding. Moreover, implementing a rate structure with fewer blocks paves the way for future rate designs that are simpler and easier to modify, analyze, administer, and understand.

Further, throughout this rate case, several parties disagreed with Minnesota Power's block rate proposal and made alternative recommendations. In fact, several parties, excluding the Company, filed a settlement purporting to resolve the proposed block rate structure ("Settlement") on the same day that initial briefing was due to be filed. This Settlement recommended a four-block rate structure. Neither the Settlement nor the Company's proposal proposed leaving the current rate structure intact. Instead, unlike the ALJ's recommendation, both the Settlement and the Company's proposal support reducing the number of blocks and simplifying rate design as appropriate goals to address Minnesota Power's current block rate structure.

Additionally, the Department recommended that the Commission require Minnesota Power, in its next rate case, to reduce the number of block rates or eliminate the block rates altogether.[180] The Company has stated its agreement with eliminating the block rate structure altogether in the next rate case, but continued use of the five-block rate structure in this proceeding will not result in the transition needed to eliminating the block rates altogether.

[180] Ex. 615 at 9 (Zajicek Rebuttal).

Continued use of the five-block rate structure, as recommended by the ALJ, is not effective. Rather, the Company urges the Commission to determine that it is reasonable for the Company to transition from a five-block Residential energy rate structure to a two-block rate structure in this rate proceeding, and that it is further reasonable to eliminate the block rate structure altogether in Minnesota Power's next rate case.

8. Meter Classification/Allocation

For many years, Minnesota Power has appropriately classified and allocated its meters as 100 percent customer costs. This classification and allocation is appropriate because a meter is needed to measure the amount of energy flow to a customer regardless of the specific quantity of demand or energy used and regardless of the meter type. Nonetheless, in this case the OAG argued that meters should be classified and allocated as 1/3 energy, 1/3 demand, and 1/3 customer based on the concept that meters – particularly advanced metering infrastructure ("AMI") meters that allow time-of-use rates and measure demand – are installed based not only on a customer's need for a meter but also on state policy goals and potential system-wide benefits.[181]

The ALJ Report found that:

> OAG "recommends" that meters should be classified as one-third energy, one-third demand, and one-third customer costs. This is because of the diverse functionality of the AMI meters which can help lower demand and energy costs. Further, according to OAG, a portion of the cost of meters is required to directly connect each customer to the distribution system. In addition, according to OAG, the PUC has recently determined that AMI meters providing controlled demand service "are more appropriately understood as demand or energy costs" which benefit the utility's system as a whole.[182] Thus, such costs should be excluded from the calculation of customers' marginal cost.

[181] Ex. 509 at 38-39 (Nelson Direct).
[182] ALJ Report at 123 (citing *In re Application of Otter Tail Power Co. for Auth. to Increase Rate for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75 (May 1, 2017)).

> The preponderance of the evidence shows that the cost of the AMI meters is more than exclusively a customer cost. However, the evidence is not clear on the proportion of the costs to be allocated. Based on the evidence in the record, it appears the customer cost would be more than one-third, while clearly not 100 percent. Because the record does not show what the correct allocation is, the question should be resolved in favor of the ratepayers. The PUC should exclude from the calculation of each customer class the cost of the meters.[183]

Minnesota Power finds this rationale confusing, but interprets the ALJ to be recommending that no portion of AMI meters should be classified as customer costs, but rather be divided between demand and energy costs in some manner. The ALJ further appears to make two conflicting findings: (1) more than 33.3 percent but less than 100 percent of AMI meter costs should be allocated as customer costs; and (2) because the record does not show the correct percentage, the issue should be resolved such that no costs (rather than an amount between 33 and 100 percent) should be allocated as customer costs. Further, the ALJ Report does not appear to speak to classification or allocation of non-AMI meters, even though only a portion of the Company's meters have been converted to AMI.

Fundamentally, the Company recommends rejecting the ALJ's conclusions on this issue and continuing to classify and allocate all of the Company's meters as 100 percent customer costs. There are several reasons for this outcome, which are not appropriately reflected in the ALJ Report:

First, whether a meter is an AMI meter or a more traditional meter, a customer still needs a meter simply to access electricity. Benefits like time-of-use rates may flow through to the system to the extent such pricing detail triggers reduced electricity consumption, but even such improved (reduced) consumption does not change the need for a meter to be attached to the

[183] ALJ Report at 123 (internal citations omitted).

customers' premises. In any event, Minnesota Power does not have a Residential—Controlled Demand service at this time like Otter Tail did.[184] Indeed, the availability of this Residential—Controlled Demand service to certain customers, rather than the meters themselves, was the focus of the Commission's decision in the Otter Tail case referenced by the OAG and ALJ.[185]

Second, the Company has already adjusted the meter price by class based on meter functionality.[186]

Third, it would be unfair to require Commercial and Industrial ("C&I") customers to pay for Residential customer meter costs because C&I customers consume energy and have peak demands that do not relate to Residential customers.[187]

Fourth, classifying and allocating meter costs other than based on customers would be unfair to the classes with a smaller number of customers (such as C&I) that have relatively higher energy and demand loads.[188] In contrast, Minnesota Power's allocation methodology for meter costs is largely based on direct assignment of costs for the Large Power class and FERC classes because those costs are identifiable.[189] The OAG's proposed allocation would undermine this cost-based allocation.

Fifth, the OAG's "1/3 energy, 1/3 demand, and 1/3 customer based" classification and allocation is arbitrary, as the OAG provides no support for the particular proposal. It appears to be primarily a mechanism to assign fewer costs to the Residential customer class, although

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[184] ALJ Report at 123 (citing *In re Application of Otter Tail Power Co. for Auth. to Increase Rate for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 75 (May 1, 2017)).
[185] *Id.*
[186] Ex. 90 (Company Response to OAG IR No. 708).
[187] Ex. 81 at 18 (Shimmin Rebuttal).
[188] Ex. 81 at 18 (Shimmin Rebuttal).
[189] Ex. 81 at 18 (Shimmin Rebuttal).

ultimately the impact is small and does not change Minnesota Power's proposed customer charge (as it did in the Otter Tail case).[190]

Minnesota Power recommends that the classification and allocation of meter costs should be consistent across meter types, without use of arbitrary classifications and allocations. Moreover, it does not make sense to conclude that more than 33 percent of metering costs should be allocated to customer costs, but then allocate no portion to customers (vs. demand or energy) simply because it is not clear how much *more* than 33 percent should be allocated to customers. Given the longstanding, well-substantiated, and Commission-approved classification and allocation of Minnesota Power meters, the record supports maintaining the current 100 percent customer allocation.

9. Green Pricing Program

Minnesota Power respectfully takes exception to the ALJ's finding that the Green Pricing Program, as proposed, is inconsistent with Minn. Stat. § 216B.169. According to the ALJ's Report, the proposed program would require customers to pay for both renewable energy sources and the fuel required for traditional generation plants.[191] As described in the Direct Testimony of Company witness Ms. Tina Koecher, the Green Pricing Program price is calculated by subtracting the unit cost to serve the target group power supply from the total program cost which includes the renewable generation source and program fees for certification and administration.[192] Therefore, customers participating in this voluntary Green Pricing Program will pay the cost of the traditional power supply for their customer class, the <u>incremental</u> cost of the renewable resource used to source the program and the miscellaneous program fees

[190] Ex. 509 at 41 (Nelson Direct) (citing Minnesota Power response to OAG IR 717 Supplemental, Schedule REN-5).
[191] ALJ Report at 52.
[192] Ex. 76 at 16 (Koecher Direct).

associated with providing this offering. As a hypothetical example, if the cost of the additional renewable energy is $30/MWh, Minnesota Power's average cost for its existing mix of renewable and nonrenewable energy sources is $20/MWh (which customers pay through base energy rates and the Fuel and Purchased Energy Adjustment), and the administration fee is $1/MWh, then the price of energy for participants in the Green Pricing Program, in addition to their normal energy billing, would be [($30/MWh +$1/MWh) - $20/MWh] = $11/MWh (equivalent to 1.1¢/kWh). The Company feels that this program, as proposed, is consistent with Minn. Stat. § 216B.169, as it reflects the difference between the cost of generating or purchasing the additional renewable energy and the cost that would otherwise be attributed to the customer for the same amount of energy based on the utility's mix of renewable and nonrenewable energy sources.

Should the Commission adopt the ALJ's recommendation to require participating customers to pay only the pro-rata share of the energy obtained from traditional sources, Minnesota Power would need to reconsider the Green Pricing Program proposal. This outcome would result in an unfair cost-shift from participating to non-participating customers and as such, the program would need to be restructured or the program pricing would need to be modified to reflect this change. Accordingly, Minnesota Power continues to support approval of the Green Pricing Program as proposed by the Company in this proceeding.

10. GRID Pilot

The GRID Pilot proposal is a project through which Minnesota Power will establish funds to demonstrate new grid modernization technologies or innovative projects in collaboration with customers and communities to proactively test the abilities, costs, and benefits

of these new technologies.[193] The pilot is meant to establish a framework and modest funding source to test the abilities, costs, and benefits of new technologies in a measured, scalable way.[194] In this proceeding, the Company is not proposing to include any costs associated with the GRID Pilot in base rates for the 2017 test year; rather, Minnesota Power proposes to utilize a GRID Pilot rider to enhance transparency and flexibility associated with the important effort to advance grid modernization. Specifically, the Company proposes a rider of $0.00085/kWh, or roughly $0.62/month and $7.43 annually for the average Residential customer.[195] This would represent an annual funding base of $2.7 million, which would be allocated to projects as determined through a selection committee process.[196]

The ALJ recommended approval of the Company's Grid Pilot and related rider with certain adjustments.[197] Specifically, the ALJ recommended that the Company "be required to match every dollar raised by the rider up to the $2.7 million requested," and that the "stakeholder advisory committee should be more defined, to include a precise number of representatives from specifically identified groups or organizations, and not to exceed 12 to 15 people representing an equal number of groups or organizations," suggesting reliance on CUB's recommendations in this proceeding regarding defining the committee and its functions.[198]

While Minnesota Power appreciates the ALJ's input and recommendation, the Company is having difficulty with understanding how the ALJ envisions the execution of the GRID Pilot and respectfully takes exception to several of the ALJ's proposed adjustments. With respect to funding, it is unclear whether the ALJ's recommendation proposes the Company's match of

[193] Ex. 76 at 23-28 (Koecher Direct); Ex. 77 at 15-22 (Koecher Rebuttal).
[194] Evidentiary Hearing Transcript, Volume 1 at 204 (Koecher).
[195] Ex. 76 at 24-25 (Koecher Direct).
[196] Ex. 76 at 25 (Koecher Direct).
[197] ALJ Report at 145.
[198] ALJ Report at 145.

dollars “raised by the rider” is a cost recovery timing and risk of approval issue or if the recommendation implies a shared ownership of regulated assets that are more long term in nature, which would be unduly complex. Regardless, Minnesota Power disagrees with the ALJ’s presumed recommendation that the Company pay $2.7 million of shareholder money to support a program that will substantially benefit ratepayers.

Further, with respect to oversight of the GRID Pilot, the Company continues to agree with the importance of establishing a GRID advisory committee that consists of a balance of stakeholders and advocates, along with technical experts and impartial industry representatives. Minnesota Power, however, disagrees with the ALJ’s recommendation to approve CUB’s proposal that the Commission undertake or approve every project’s selection. While the Company agrees with Commission input on the guidelines for project selection, requiring Commission authority over final project selection deters from one of the primary objectives of the pilot – to allow Minnesota Power to respond to technology changes without being affixed to an existing regulatory program.

Minnesota Power continues to believe that the GRID Pilot is an important proposal in this proceeding and will benefit both ratepayers and the Company long term. However, the ALJ Report states recommendations that confuse the execution of the GRID Pilot. As such, the Company suggests adoption of the cost recovery framework and related tariff in this proceeding with further consideration of the proposed pilot implementation specifications such as the stakeholder advisory committee, project selection and evaluation, and reporting requirements to be addressed as part of a compliance filing.

B. Clarifications

1. EITE

The ALJ provided a procedural summary of the separate EITE proceeding (Docket No. E015/M-16-564) and concluded that the "EITE subsidy incurred by non-EITE customers appears to be non-existent at the current time."[199] It is not clear whether the ALJ recommends that the additional revenues from the restart of the Keetac facility be included in this rate case or in the EITE proceeding. Based on the totality of the ALJ Report, the Company believes that the ALJ intended for the additional Keetac facility revenues (of nine months of operation) to be included in this rate review and not in the EITE proceeding. Consistent with the Company's petition for reconsideration, as cited by the ALJ, the Company supports this treatment of these revenues. Further, as noted in the Company's petition for reconsideration in Docket No. E015/M-16-564, Minnesota Power must be allowed to maintain revenue neutrality, as required under Minn. Stat. § 216B.1696.

2. Fuel Clause Adjustment

The ALJ reached several conclusions related to the fuel clause adjustment calculation methodology, the fuel clause transition cost recovery, and the Company's base cost of fuel to reach a recommendation that any decision on these items be deferred to decisions made by the Commission in Docket No. E999/CI-03-803. The Company agrees with this recommendation and is awaiting a written decision in that Docket to evaluate what impact that decision may have on the Company's fuel clause calculation methodology, the fuel clause transition cost recovery amount, and the base cost of fuel. Therefore, no adjustment is warranted.

[199] ALJ Report at 153.

3. Employee Expenses

The ALJ concluded, based on recommendations of the OAG, that the Company "did not include the data necessary to determine the business purpose of expenses in every itemization" of employee expenses, "[e]ven if the vendor is easily identified."[200] In reaching this conclusion, the ALJ recommends excluding $27,520 (Total Company) of employee expenses.[201]

While the Company disagrees with the ALJ's conclusions regarding whether it met the requirements under the Employee Expense Statute to provide the required information, the Company is not going to take exception to the ALJ's recommendation to exclude $27,520 (Total Company) from employee expenses at this time. The Company will review the information it provides regarding employee expenses that are reimbursed directly to employees for out-of-pocket expenses and evaluate how it will provide that information in the next rate case.

4. Generation Supervision and Engineering and Distribution Meter Reading

The Company takes no exception to the ALJ's conclusions and recommendations regarding the Company's Generation Supervision and Engineering and Distribution Meter Reading budgets, but provides these comments to confirm its commitment to providing information in future rate cases that will aid the parties in their review.

The ALJ concluded that the Company's test year budget for Generation Supervision and Engineering and Meter Reading expenses was reasonable.[202] In reaching this conclusion, the ALJ rejected the Department's argument that these budgets were excessive because there were year-to-year variations in select FERC accounts that comprise the Generation and Distribution O&M budgets. While the Company agrees with the ALJ's recommendation, the Company also understands that part of the Department's concern with these O&M expenses was the result of

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[200] ALJ Report at 84.
[201] ALJ Report at 85.
[202] ALJ Report at 103.

how these expenses were presented in the initial filing. In an effort to make the Company's test year O&M budgets more transparent, the Company has agreed to abide by the Department's filing recommendation for the Company's next rate case.[203] The Company also acknowledges the ALJ's footnoted suggestion regarding expenses budgeted for in one account but actual expenses accounted for in a different account and agrees that it would be helpful to minimize such discrepancies to the extent practicable.[204] The Company expects that abiding by these requirements includes connecting RC O&M expenses to FERC Accounts and will assist other parties review of the reasonableness of these budgets.

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[203] Ex. 630 at 81 (Campbell Surrebuttal); Evidentiary Hearing Transcript, Volume 2 at 101:13-20 (Podratz).
[204] ALJ Report at 103 n.782.

III. DISPUTED ISSUES NOT ADDRESSED IN ALJ REPORT

A. Spot Bonuses

Spot Bonuses are performance-based incentive compensation for non-bargaining, non-management employees that are paid either through payroll or as gift cards (if in small denominations).[205] Spot bonuses recognize employees' extraordinary efforts and accomplishments for the benefit of customers and the Company. For instance, in 2016, the Company awarded Spot Bonuses to certain employees who assisted in the around-the-clock storm restoration and response to restore power to 47,000 Duluth area customers.[206]

Spot Bonuses are also a key component of the Company's overall compensation package. Based on a 2016 Salary Benchmark Survey, Minnesota Power's total annual cash compensation (base salary plus Annual Incentive Plan ("AIP") pay) for non-bargaining, non-management employees is, on average, five to ten percent below the market median.[207] Minnesota Power uses Spot Bonuses to help narrow the gap between top performing employees' compensation and market compensation in an effort to retain these top employees.[208]

In 2017, the Company expanded its AIP to certain key non-management employees to further close this pay gap. As a result, in 2017, 147 employees who are eligible for AIP are also eligible for Spot Bonuses.[209] The Department recommended a reduction of the Company's proposed Spot Bonus expense to exclude expenses for Spot Bonuses paid to employees who were also eligible for AIP and whose Spot Bonus award was not tied to storm restoration.[210] The

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[205] Ex. 58 at 17 (Johnson Rebuttal).
[206] Ex. 58 at 17-18 (Johnson Rebuttal).
[207] Ex. 58 at 18 (Johnson Rebuttal).
[208] Ex. 58 at 18 (Johnson Rebuttal).
[209] Ex. 58 at 21 (Johnson Rebuttal).
[210] Ex. 632 at 15 (Lusti Surrebuttal).

Department concluded that it was not reasonable for ratepayers to pay for Spot Bonuses in addition to AIP for these key non-management employees.[211]

While the ALJ did not directly address the issue of Spot Bonuses in his report, the ALJ did acknowledge that:

> Barring excessive compensation levels, skewed incentives, or other public policy concerns, the Company has the discretion to structure its compensation packages in accordance with its best business judgment.[212]

The ALJ also recognized that "[t]o provide safe and reliable service, the Company needs to be able to offer competitive compensation packages to its employees."[213] This rationale supports the reasonableness of the Company's Spot Bonus expense.

Total cash compensation for Minnesota Power's non-management employees is five to ten percent below the market median in 2016.[214] As a result, Spot Bonuses do not result in excessive compensation but rather are essential to ensuring that Minnesota Power's compensation package is market competitive. As Minnesota Power's proposed Spot Bonus expenses are a necessary component of market-competitive compensation for non-management employees, these costs are reasonable costs of service and should be included in final rates.

B. <u>Other Employee Benefits</u>

In its "Other Benefit" expense, Minnesota Power included costs for a variety of employee benefits including: life insurance, flexible compensation plan, employee tuition reimbursement, EIP survivor benefits, long-term disability plan, self-insured worker's compensation, and other

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[211] Ex. 632 at 15 (Lusti Surrebuttal).
[212] ALJ Report at 44 (citing *In re Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 29 (Nov. 2, 2010)).
[213] ALJ Report at 44 n.371 (quoting *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 42 (July 3, 2013)).
[214] Ex. 56 at 25 (Johnson Direct).

miscellaneous expenses that include the costs to administer other employee benefits.[215] These benefits are necessary components to ensure that the benefits offered by Minnesota Power are comparable to those offered by similar employers. The Department disputed the Company's test year amount for these Other Benefits and recommended using a three-year average because the test year expenses are higher than the previous three years.[216]

The ALJ Report did not address the reasonableness of the Company's proposed Other Benefit costs. However, the Company has met its burden of proof in demonstrating that its proposed test year expenses for "Other Benefits" are reasonable.

To develop the test year budget for "Other Benefit" expenses, Minnesota Power took into account all factors necessary to accurately compute the test year expense such as yearly salary increases that impact the costs of life insurance and flexible compensation program as well as the number of participants in each program that varies each year.[217] Utilizing a three-year average proposed by the Department would not take into account these specific factors and would substantially underestimate Minnesota Power's test year costs for Other Benefits.

Minnesota Power also provided evidence that explained why four categories of Other Benefit 2017 test year expenses were higher than 2015 and 2016.[218] For instance, for the flexible compensation expense, the Company noted that this plan includes annual market rate adjustments for non-bargaining unit employees which increases this expense year-over-year thus resulting in a higher test year expense as compared to prior years.[219] Minnesota Power also explained that the increase in "other-miscellaneous" expenses in 2017 is due to the need to provide communications to employees regarding their benefits that the Company is required to

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[215] Ex. 58 at 29-30 (Johnson Rebuttal).
[216] Ex. 629 at 109 (Campbell Direct).
[217] Ex. 58 at 31 (Johnson Rebuttal).
[218] Ex. 58 at 30 (Johnson Rebuttal).
[219] Ex. 58 at 31 (Johnson Rebuttal); Ex. 58 at Schedule 5 (Johnson Rebuttal).

complete at least every five years by the Department of Labor.[220] While these communications were not completed in any of the three prior years included in the Department's proposed average, the 2017 test year budget includes the expenses associated with these federally-required communications.[221]

Notably, the Department did not dispute any of the Company's evidence offered to support either the reasonableness of the Company's budgeting process or its explanations for why test year expenses were higher than prior years. Instead, the Department continued to support a three-year average due to the "volatile" nature of these expenses.[222] However, this observation is not sufficient to overcome the record evidence that demonstrates that Minnesota Power's request, while higher than the three-year average, is representative of actual costs to be incurred by the Company. The Company's proposed test year expense for "Other Benefits" is reasonable and should be adopted by the Commission.

C. <u>Transmission Revenue and Expense</u>

In this rate proceeding, the Company, the Department, and the OAG disagreed as to the appropriate amount to include in the 2017 test year for third-party Transmission revenues and expenses.[223] The ALJ, however, did not provide an analysis or clearly-identified recommendation on how third-party Transmission revenues and expenses should be accounted for in the 2017 test year.

Third-party Transmission revenues and expenses are comprised of both revenue and expenses that are not within Minnesota Power's control.[224] The most significant source of

[220] Ex. 58 at 31 (Johnson Rebuttal).
[221] Ex. 58 at 31 (Johnson Rebuttal).
[222] Ex. 630 at 48 (Campbell Surrebuttal).
[223] ALJ Order Denying Motions in Limine to Exclude Surrebuttal Testimony of Christopher Fleege at 10 (eDockets Document ID No. 20178-134557-01).
[224] Ex. 50 at 31 (Fleege Rebuttal).

revenue in this category is from Transmission Service Requests ("TSRs").[225] These TSRs do not serve Company load, but rather seek use of the Company's transmission system for delivery of energy.[226] While these TSRs are a welcome source of revenue for the Company, they are not within the Company's control.[227]

The Company's initial filing included an estimate of third-party Transmission revenue and expense, with a net revenue of $0.02 million (Total Company).[228] After the initial filing, more current information became available and, as a result, the Company recommended, in response to the Department's request in its Direct Testimony, that the net revenue be increased by $2.22 million (Total Company).[229] The Department agreed with this update.[230]

On July 18, 2017, the Company learned that two TSRs previously set to Minnesota Power pricing zones (delivery points or "sinks") were not renewed and the third-party revenues included for these TSRs in the 2017 test year were not rolled over starting in July 2017. Given the late date of the availability of this further update, the Company provided not only the revenue requirement impact of these lost TSRs, but also both the raw data sets from MISO and annotated data sets to show the permanent transfer of this sink from the Minnesota Power pricing zone to another pricing zone, with its Surrebuttal Testimony.[231] As a result of these lost TSRs, the Company requested that its third-party Transmission revenues and expenses be updated to reflect a full year impact, resulting in a reduction of $6.23 million (Total Company) from the net

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[225] Ex. 50 at 31 (Fleege Rebuttal).
[226] Ex. 50 at 31 (Fleege Rebuttal).
[227] Ex. 50 at 31 (Fleege Rebuttal).
[228] Ex. 50 at Schedule 14, "2017 Test Year Budget" column (Fleege Rebuttal).
[229] Ex. 50 at 31 (Fleege Rebuttal).
[230] Ex. 630 at 18 (Campbell Surrebuttal).
[231] Ex. 51 at Schedule 1 and n.2 (Fleege Surrebuttal).

revenue amount updated at the Department's request in the Company's Rebuttal Testimony.[232] Parties argued that the data should not be allowed because it became available late in the process.

Overall, after the Department sought to update the net revenue (expense) amounts for third-party Transmission revenue and expense, the Company kept the record updated along the way, through Rebuttal Testimony and Surrebuttal Testimony, with the best information available to the Company at the time. The Company promptly updated the record to include new known information that impacted the Company's third-party Transmission revenues but over which the Company has no control. Because these impacts are known to affect the Company's third-party Transmission revenue and expense amount, the Company's requested adjustment in Surrebuttal Testimony is warranted. Consistent with the ALJ's conclusion related to another issue that "[t]here may be situations where such late filing is warranted,"[233] the Company's test year should be adjusted to reflect this information that became available just prior to the filing of Surrebuttal Testimony in this case.

D. <u>Non-Labor Transmission Expense</u>

In its Surrebuttal Testimony, for the first time, the Department took issue with the Company's Transmission O&M expenses and recommended an adjustment based on comparing Minnesota Jurisdictional increases between 2012 and 2016 to the increase between 2016 and the 2017 test year without considering the impact of the jurisdictional allocator.[234] The ALJ did not address the Department's position in his report.

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[232] Ex. 51 at 4 (Fleege Surrebuttal).
[233] ALJ Report at 74.
[234] Ex. 630 at 21 and Schedule NAC-S-1 (Campbell Surrebuttal); Ex. 93 (Department Response to Company IR No. 14).

The average year-over-year increase for the 2012 to 2016 period, comparing the Minnesota Jurisdictional amounts, is 10.64 percent.[235] The year-over-year increase for the Minnesota Jurisdictional amount of Transmission 2016 actual to the 2017 test year Transmission O&M Minnesota Jurisdictional amount is 16.39 percent.[236] Based on this, the Department recommended in Surrebuttal Testimony that the year-over-year, 2016 to 2017, expense be held to the 10.64 percent average experienced from 2012 to 2016.[237]

The Department, in making this recommendation, however, chose to ignore the real cause of this year-over-year percentage difference: an increase in the amount of Total Company expense allocated to the Minnesota jurisdiction[238] and not a change in Company spend patterns. The Minnesota jurisdictional allocation increased in 2017 due to higher sales to retail customers, which is also the reason for some of the Company's expense increases in 2017. When the jurisdictional allocator is removed and the Total Company average year-over-year increase for the period of 2012 to 2016 is calculated, it is also 10.64 percent because the Company's jurisdictional allocator is consistent for 2012 through 2016.[239] When comparing the Transmission O&M expense increase from 2016 actual to 2017 test year on a Total Company basis, the increase is only 9.15 percent and less than the 2012 to 2016 actual average increase, the time frame over which the Department advocated an average should be established.[240]

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[235] Ex. 93 (Department Response to Company IR No. 14).
[236] Ex. 630 at Schedule NAC-S-1 (Campbell Surrebuttal).
[237] Ex. 630 at 21 (Campbell Surrebuttal).
[238] In other terms, a change in the allocation factor from the 2010 rate case, used for 2012 to 2016, and the revised allocation factor in the 2016 rate case, of which no party took issue. Evidentiary Hearing Transcript, Volume 4 at 100:12-16 (Campbell).
[239] Ex. 93 (Department Response to Company IR No. 14); Ex. 630 at Schedule NAC-S-1 (Campbell Surrebuttal).
[240] Ex. 93 (Department Response to Company IR No. 14); Evidentiary Hearing Transcript, Volume 4 at 104:12-17 (Campbell).

Although the Department consistently compared Total Company average increases when evaluating other Company expenses for reasonableness in this proceeding,[241] the Department selectively chose to use the Minnesota Jurisdictional amount over a period of years with different allocation factors to evaluate Transmission O&M expense.[242] Evaluating or averaging using the Minnesota Jurisdictional amount when the jurisdictional allocator changes creates an unfair bias in the evaluation process. The reasonableness of these expenses and revenues should be evaluated at the Total Company level, as that is the level at which the costs are consistent across a range of years independent of allocation factors. The allocator, which here is uncontested in its own right, is then applied to determine the appropriate ratemaking number. Therefore, the Company's Transmission O&M 2016 actual to 2017 test year budget increase of 9.15 percent is less than the 2012 to 2016 actual average annual increase of 10.64 percent. Independent of allocators, this increase satisfies the Department's logic that 2017 transmission expense increases should be in line with historic averages. As such, it is a reasonable level of expense, especially given that the Department did not contest the reasons these costs are being incurred.

E. <u>Retirement Savings and Stock Ownership Plan</u>

Another component of Minnesota Power's employee compensation and benefit package is the RSOP. The Department disputed the Company's test year RSOP expenses claiming that the test year amount was "too high of an increase" over the 2016 actual RSOP costs and recommended a three-year average (2014-2016) to calculate the test year expense.[243]

While the ALJ did not directly address the Company's RSOP expenses, the undisputed evidence proffered by Minnesota Power supports a Commission finding as to the reasonableness

[241] *See* Ex. 626 at 7-8 (La Plante Direct); Ex. 624 at 35-36 (Ouanes Direct).
[242] Ex. 93 (Department Response to Company IR No. 14); Evidentiary Hearing Transcript, Volume 4 at 107:10-14 and 108:1-21 (Campbell).
[243] Ex. 629 at 68-69 (Campbell Direct).

of these expenses. Specifically, in response to the Department's concerns, Minnesota Power provided a thorough explanation as to why the Company's 2016 actual RSOP costs were lower than the 2017 test year expenses.

The Company noted that the 2016 RSOP costs included a one-time dividend credit, which resulted in 2016 actuals being ten percent lower than 2017 costs. This dividend credit was the result of a transition in the structure of Minnesota Power's benefits package. Minnesota Power's leveraged employee stock ownership plan ("ESOP") was supported by a loan, payments to which were made from ALLETE's stock dividends. This loan was paid off in full as of December 2015.[244] Therefore, rather than use the December 1, 2015, ALLETE Stock dividend to pay toward that loan, the Company was able to use those dividends to make an additional contribution into the trust that supports the RSOP.[245] The amount of the 2016 employer contribution for the RSOP was reduced by this dividend credit.[246] As a result, because of a one-time event related to the expiration of the ESOP loan, the Company was able to reduce its 2016 RSOP expense. Such dividend credits are not likely to recur because in the Company's current plan design, all dividends are paid directly to the participants.[247]

Further, the Company explained that variances related to salary adjustments, employee deferral rates, union status, date of birth, and hire date resulted in the 2017 test year RSOP expenses being five percent higher than 2016.[248] For example, a bargaining unit employee that leaves the Company was receiving a one percent RSOP contribution, but the employee hired to replace them will now be eligible for an RSOP contribution of up to twelve percent.[249]

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[244] Ex. 58 at 28 (Johnson Rebuttal).
[245] Ex. 58 at 27-28 (Johnson Rebuttal).
[246] Ex. 58 at 28 (Johnson Rebuttal).
[247] Ex. 58 at 27-28 (Johnson Rebuttal).
[248] Ex. 629 at 69 and Schedule NAC-20 at 2 (Campbell Direct).
[249] Ex. 58 at 28 (Johnson Rebuttal).

The Department did not provide any evidence to refute the Company's proffered explanations and thus the Commission should adopt the Company's proposed test year RSOP expense.

F. Residential Time-of-Use Rider

The ALJ Report did not address the OAG's recommendation that that the Commission order the Company to propose an opt-out TOU rate design for Residential customers in the next rate case.[250] The OAG's recommendation must be rejected, however, as Minnesota Power cannot definitively state at this time that such an offering would be feasible by the Company's next rate case.[251] While Minnesota Power has been working to install additional AMI meters throughout its system that would have the capability for TOU rates, system-wide AMI installation is not yet complete, nor has it been fully vetted across the system.[252] Accordingly, the Residential Time-of-Day Pilot docket (Docket No. E015/M-12-233), that the Commission recently reviewed and modified, is the most appropriate avenue to analyze the OAG's proposal.[253]

[250] Ex. 509 at 93 (Nelson Direct).
[251] Ex. 86 at 29 (Podratz Rebuttal).
[252] Ex. 86 at 29 (Podratz Rebuttal).
[253] Ex. 86 at 29 (Podratz Rebuttal).

IV. RESOLVED ISSUES NOT ADDRESSED IN ALJ REPORT

Several issues that Minnesota Power considers resolved among the parties were not addressed in the ALJ Report. To ensure that these issues are not overlooked when the Commission deliberates and an order is written, and to confirm an accurate record is presented for the Commission's deliberations, the Company briefly summarizes the following resolved issues.

A. Hibbard Generator Extended Depreciation

The Department recommended extending the depreciation life of the HREC to 2029 compared to the year 2024 assumed in the Company's initial rate case filing, so that rates associated with this facility are consistent with the depreciable life established in depreciation and resource planning dockets resolved after the initial rate case was assembled.[254] Minnesota Power agreed the life of the HREC should be extended to 2029 consistent with the Company's most recently approved IRP, resulting in a Minnesota Jurisdictional reduction of $846,393 to depreciation reserve, an increase of $350,153 (MN Jurisdictional) to accumulated deferred income taxes,[255] and a reduction of $1,692,786 (MN Jurisdictional) to depreciation expense.[256] The Company intends to add a request to extend HREC's life to the Company's open 2017 annual depreciation filing in Docket No. E015/D-17-118.[257]

B. Sales Forecast

1. Paper and Pulp

Minnesota Power has four Large Power paper customers that operate four pulp and paper mills.[258] Minnesota Power serves approximately 54 percent of the full production of energy

[254] Ex. 629 at 33-34 (Campbell Direct).
[255] Ex. 42 at 7 (Minke Rebuttal); Ex. 86 at 4-5 (Podratz Rebuttal).
[256] Ex. 86 at 11 (Podratz Rebuttal).
[257] Ex. 42 at 7 (Minke Rebuttal).
[258] Ex. 61 at 31 (Perala Direct).

demand for these facilities, with customers' on-site generation providing the remainder.[259] Minnesota Power's test year sales forecast for these four Paper and Pulp customers reflected a 9.3 percent or approximately 124,000 MWh decrease as compared to Minnesota Power's 2016 Annual Utility Forecast Report.[260] This change was made to reflect reduced energy sales to two paper customers as a result of changes to their self-generation profile.[261] One customer installed a new turbine generator and subsequently began nominating and taking less energy from Minnesota Power.[262] The other customer exercised an option to gain ownership of a generator previously owned by Minnesota Power.[263]

The OAG disputed the Company's forecasted reduction in sales to Paper and Pulp customers and asserted that a sales forecast in line with recent years would be more reasonable given the recently-approved EITE rate and potential federal trade protections for domestic businesses.[264] Minnesota Power disagreed with the OAG's assessment noting that the reductions in sales are due to changes in customer self-generation profiles.[265] In addition, Minnesota Power provided evidence of recent market-related shutdowns of paper mills despite the implementation of the EITE credit in February 2017.[266] Minnesota Power's conclusion and overall concerns with the paper sales forecast was further reinforced by UPM Blandin's recent announcement of its permanent closure of its Paper Machine 5.[267] In Surrebuttal Testimony, the OAG withdrew its recommendation to increase the test year sales forecast for Paper and Pulp customers.[268]

[259] Ex. 61 at 31 (Perala Direct).
[260] Ex. 67 at Schedule 1 (Pierce Direct).
[261] Ex. 61 at 31 (Perala Direct).
[262] Ex. 61 at 31 (Perala Direct).
[263] Ex. 61 at 31 (Perala Direct).
[264] Ex. 501 at 49 (Lebens Direct).
[265] Ex. 65 at 20 (Perala Rebuttal).
[266] Ex. 66 at 20 (Perala (TS) Rebuttal).
[267] *See* Notice of Blandin Service Change (Oct. 25, 2017) (eDockets Document ID No. 201710-136825-01).
[268] Ex. 504 at 30 (Lebens Surrebuttal).

2. *Magnetation*

Magnetation has four plants in northeastern Minnesota that produce iron concentrates, of which three of those plants, Plants 2, 3, and 4, received electric service from Minnesota Power.[269] Plant 3, otherwise known as Mining Resources, is a joint venture between Steel Dynamics (80 percent) and Magnetation (20 percent).[270] The drop in global iron ore pricing in 2014 came right after Magnetation completed two major capital projects and severely impacted Magnetation's profitability and revenues.[271] Magnetation subsequently filed for Chapter 11 bankruptcy in May 2015 and idled Plant 2 in early 2015 and Plant 4 in the fall of 2016.[272] Plant 3, built primarily for supply of iron concentrates to the Mesabi Nugget facility, idled operations in 2015 due to Steel Dynamics indefinite idling of its iron nugget production facility in January 2015.[273] Minnesota Power's 2017 test year sales forecast reflects no energy sales to Plant 2 or Plant 4 with minimal sales to Plant 3 consistent with the care and maintenance of the facilities.[274] In January 2017, the bankruptcy court approved ERP Iron Ore, LLC's ("ERP") purchase of substantially all of Magnetation's assets, including Plant 2 and Plant 4.[275]

In Direct Testimony, the OAG recommended that the sales forecast be increased to reflect full production of Plant 4 for six months of the test year.[276] The OAG based this recommendation on statements made by the Chief Executive Officer of ERP in a February 2, 2017, news article where he stated that ERP planned to restart operations at Plant 4 by June 30, 2017, at the latest.[277] As of the filing of Rebuttal Testimony on June 29, 2017, Plant 4 remained

[269] Ex. 61 at 25 (Perala Direct).
[270] Ex. 61 at 25 (Perala Direct).
[271] Ex. 61 at 26 (Perala Direct).
[272] Ex. 61 at 26 (Perala Direct).
[273] Ex. 61 at 26 (Perala Direct).
[274] Ex. 61 at 27 (Perala Direct).
[275] Ex. 64 at 7 (Perala Second Supplemental Direct).
[276] Ex. 500 at 52-53 (Lebens Direct).
[277] Ex. 500 at 51 (Lebens Direct).

idled.[278] As Minnesota Power explained, restart of Plant 4 is dependent on ERP securing customer contracts to buy the iron ore concentrate and that ERP acknowledged in the February 2017 article that no such contracts had been executed.[279] Minnesota Power further noted that no clear timeline for restart of Plant 4 has been provided to Minnesota Power by ERP.[280] In Surrebuttal Testimony, the OAG withdrew its recommendation to increase the test year sales forecast to account for six months of sales to Plant 4.[281] However, the OAG reserved the right to provide a new recommendation after reviewing the August nominations from ERP.[282] Prior to the evidentiary hearing, Minnesota Power provided a copy of the August demand nominations for ERP to the OAG.[283] At the evidentiary hearing, Company witness Mr. Michael Perala testified that the Company has been in frequent communication with ERP and "at this time there is still no definitive start-up plans for their facilities."[284] Following review of the August demand nominations and testimony at the evidentiary hearing, the OAG agreed that no change to Minnesota Power's test year sales forecast is necessary due to Magnetation's operations.[285]

3. Mustang

In Direct Testimony, OAG witness Mr. Brian Lebens recommended that Minnesota Power's 2017 test year sales forecast be increased to include additional sales to Cliffs Natural Resources' United Taconite Plant due to the Commencement of Project Mustang in May 2017. In Rebuttal Testimony, Minnesota Power provided evidence that there was no increase in sales due to Project Mustang and that load has actually been lower since the start of production of the

[278] Ex. 65 at 13 (Perala Rebuttal).
[279] Ex. 64 at 7 (Perala Second Supplemental Direct).
[280] Ex. 65 at 13(Perala Rebuttal).
[281] Ex. 504 at 32 (Lebens Surrebuttal).
[282] Ex. 504 at 32 (Lebens Surrebuttal).
[283] Ex. 513 (Company Response to OAG IR No. 1162 (TS)); Ex. 514 (Company Response to OAG IR No. 1162 (P)).
[284] Evidentiary Hearing Transcript, Volume 1 at 139 (Perala).
[285] Evidentiary Hearing Transcript, Volume 2 at 259 (Lebens).

new Mustang pellet.[286] The OAG withdrew its recommendation related to Project Mustang after reviewing the information provided by the Company.[287] As no other party recommended adjustments to the test year sales forecast for Project Mustang, the Company considers this issue resolved such that no adjustment is warranted.

C. Pension Expense

The Company's initial filing in this rate case included its forecasted pension expense for 2017 based on the estimate available at the time of filing. In Direct Testimony, the Department recommended that Minnesota Power use the subsequent December 31, 2016, measurement date for pension expense, resulting in using the Company's actual 2017 pension expense for the test year.[288] The Company agreed with the Department's recommendation to use the December 31, 2016, measurement date for the pension expense and further updated the allocation of the Company's pension expense between Minnesota Power and ALLETE subsidiary Superior Water, Light & Power.[289] These changes reduced pension expense by $519,375 on a Minnesota Jurisdictional basis, resulting in a pension expense of $5,200,194 for the 2017 test year.[290]

D. Interest on Benefits and Other Awards

Interest on Benefits and Other Awards is a budget category that includes (a) interest expense on outstanding legacy employment agreements during the 1980s and 1990s; and (b) gift cards used for performance-based awards for qualifying employees.[291] Minnesota Power originally budgeted $181,067 (Total Company) for the 2017 test year for Interest on Benefits and Other Awards.[292]

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[286] Ex. 66 at 16, Schedule 11 (Perala (TS) Rebuttal).
[287] OAG Initial Brief at 10-11 (eDockets Document ID No. 20179-135457-02).
[288] Ex. 629 at 77 (Campbell Direct).
[289] Ex. 38 at 25-26 (Cutshall Rebuttal).
[290] Ex. 38 at 25-26 (Cutshall Rebuttal); Ex. 86 at 12 (Podratz Rebuttal); Ex. 630 at 17 (Campbell Surrebuttal).
[291] Ex. 631 at Ex. DVL-16 (Lusti Direct).
[292] Ex. 631 at Ex. DVL-9 (Lusti Direct).

In Direct Testimony, the Department recommended exclusion of the Company's budget for Interest on Benefits and Other Awards on the basis that the number of Company employees eligible to participate for the first time in the Company's AIP was different from what the Department expected.[293] In discovery, the Company explained that the interest expenses had been incurred in connection with hiring and retaining uniquely skilled employees whose service provided benefits to the Company's customers and ratepayers.[294] Minnesota Power also explained that as it reviewed the budget for Interest on other Benefits and Awards, it found a bookkeeping error, and accordingly reduced the portion of Interest on other Benefits and Awards associated with gift cards to $64,802 (MN Jurisdictional) (on a Total Company level, this was reduced from $91,000 to $74,474).[295] The test year expense was reduced by $16,526 (Total Company), or $14,380 on a Minnesota Jurisdictional basis.[296] With these clarifications, the Department did not oppose the adjusted budget for Interest on Benefits and Other Awards but requested that the Commission require Minnesota Power to provide documentation to show that the interest applied only to retirees who were not eligible for AIP when they worked for Minnesota Power.[297] In her opening statement at the evidentiary hearing, Company witness Ms. Nicole Johnson explained that these employment agreements were necessary to hire and retain specific employees with unique skills and talents, and have no correlation to whether or not these employees also received AIP.[298] As a result, it would not be appropriate to tie recovery of the interest on these agreements to these employees' AIP eligibility. In his opening statement at the

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[293] Ex. 631 at 22 (Lusti Direct).
[294] Ex. 631 at Ex. DVL-16 (Lusti Direct).
[295] Ex. 631 at Ex. DVL-16 (Lusti Direct); Ex. 58 at 19 (Johnson Rebuttal).
[296] Ex. 86 at 12 (Podratz Rebuttal).
[297] Ex. 632 at 16-17 (Lusti Surrebuttal).
[298] Evidentiary Hearing Transcript, Volume 2 at 92 (Johnson).

evidentiary hearing, Department witness Mr. Dale Lusti stated that this issue was resolved between Minnesota Power and the Department.[299]

No other parties commented on Interest on Benefits and Other Awards.

E. Base Cash

In this rate proceeding, Minnesota Power proposed to roll projects for which costs are currently being recovered in riders into base rates wherever those projects were in service by December 31, 2016.[300] The Department expressed concern that the Company is still collecting actual cash through the riders to cover the costs of these projects, whereas the amounts included in base rates for rider cash collections are based on estimates; therefore, it is necessary to ultimately "true up" the actual cash collected from riders in 2017 and as recognized in base rates.[301] Both the Company and the Department agree that it would be reasonable for the true-up to be included in Minnesota Power's riders for the period through or until final rates go into effect.[302] For the Company's next rate case, the Department also recommended that the Commission require that cost recovery for facilities either be rolled in at the beginning of the rate case, and then no longer recovered in riders, or that facilities and rider collections be rolled into the rate case at the end of the rate case if the Company wants to continue rider recovery.[303] The Company is agreeable to this Department recommendation.

F. High Performance Awards

High Performance Awards are a form of employee compensation designed to reward non-bargaining unit, non-management employees who have exhibited exceptional

[299] Evidentiary Hearing Transcript, Volume 4 at 175 (Lusti).
[300] Ex. 40 at 3 (Minke Direct); Ex. 42 at 2 (Minke Rebuttal).
[301] Ex. 629 at 92-93 (Campbell Direct).
[302] Evidentiary Hearing Transcript, Volume 1 at 74 (Minke); Ex. 630 at 64 (Campbell Surrebuttal).
[303] Ex. 630 at 65 (Campbell Surrebuttal).

performance.[304] For the 2017 test year, Minnesota Power budgeted $348,052 (MN Jurisdictional) for High Performance Awards.[305]

In Direct Testimony, the Department recommended exclusion of the Company's budget for High Performance Awards on the basis that the number of Company employees eligible to participate for the first time in the Company's AIP was different from what the Department expected, which might also affect High Performance Award eligibility/receipt.[306] However, in Rebuttal Testimony, the Company explained that employees eligible for AIP are not eligible for High Performance awards.[307] With this clarification, the Department concluded that the Company's position as to the High Performance Awards was reasonable and recommended no adjustment.[308] No other parties commented on High Performance Awards.

G. Economic Development Expenses

In Direct Testimony, the Department recommended approval of 50 percent of the Company's proposed economic development expenses, consistent with Minnesota Power's initial proposal.[309] The Department, however, pointed out an apparent discrepancy in the amount of 2017 test year economic development expenses requested by the Company in its initial filing and in Minnesota Power's response to a Department information request. Minnesota Power clarified that while the correct amount was included in the rate case revenue requirement and reflected in the information request response, the apparent discrepancy was due to a number of transcription errors in testimony that were corrected in the Company's errata filing.[310] Further, based on the Company's updated jurisdictional allocation factors included in Minnesota Power's

[304] Ex. 56 at Schedule 3 (Johnson Direct).
[305] Ex. 56 at Schedule 3 (Johnson Direct).
[306] Ex. 631 at 18 (Lusti Direct).
[307] Ex. 58 at 21 (Johnson Rebuttal).
[308] Ex. 632 at 13 (Lusti Surrebuttal).
[309] Ex. 621 at 2-8 (Davis Direct).
[310] Ex. 33 at 28 (McMillan Rebuttal).

Supplemental Direct Filing, Minnesota Power's rate recovery request for economic development expenses changed slightly, totaling $207,749 on a Minnesota Jurisdictional basis.[311] The Department agrees with the updated economic development expenses based on the changes to jurisdictional allocation factors.[312]

H. <u>CIP Expenses</u>

On November 3, 2016, Minnesota Power's final 2017 CIP budget was approved in Docket No. E015/CIP-16-117.[313] The approved 2017 CIP budget was reduced by $125,000 (Total Company and MN Jurisdictional) for a pilot program that was not approved. In Rebuttal Testimony, Minnesota Power agreed that the rate case should reflect this adjustment and removed $125,000 of conservation expense from the 2017 test year. Minnesota Power and the Department agree that the Commission-approved Minnesota Jurisdictional test year CIP expense is $10,447,625 and that this amount will be built into base rates.[314]

I. <u>Fuel Clause Adjustment – Market Charges</u>

In its initial filing, the Company requested approval to include Market Charges of non-MISO ISOs and RTOs that the Company may participate in for the benefit of its customers in the fuel clause adjustment.[315] In Direct Testimony, the Department and the OAG agreed to the Company including these charges, should they occur, in the fuel clause adjustment, so long as they are for energy charges only and not for administrative costs.[316] In Rebuttal Testimony, the

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[311] Ex. 33 at 28-29 (McMillan Rebuttal).
[312] Ex. 623 at 6 (Davis Surrebuttal).
[313] *In the Matter of Minn. Power's 2017-2019 Elec. Conservation Improvement Program Plan*, Docket No. E015/CIP-16-117, DECISION (Nov. 3, 2016).
[314] Ex. 86 at 13-14 (Podratz Rebuttal); Ex. 623 at 7 (Davis Surrebuttal).
[315] Ex. 72 at 30 (Oehlerking-Boes Direct).
[316] Ex. 626 at 20 (La Plante Direct).

Company confirmed that it would not include any administrative costs in the fuel clause adjustment for ISO/RTO Market Charges.[317]

J. Business Development Incentive Rider

Minnesota Power has proposed the BDI Rider as a new product offering that would apply a discount on a temporary basis to new or existing customers that have incremental load of at least 350 kW. It is intended to help encourage regional economic development by providing an incentive for additional load or new business on Minnesota Power's system.[318] The Department and OAG each took positions on this rider, recommending several conditions for approval, to which the Company has agreed. Specifically, (1) the BDI Rider should be approved with a requirement to obtain approval of amendments to existing electric service agreements ("ESAs") or any new ESAs;[319] (2) new or amended ESAs should be submitted for approval no later than 30 days after the Company signs a new ESA to be served under the BDI Rider; (3) the ESA filing with the Commission would contain the incremental revenue and incremental costs associated with the new ESA; (4) if no party objects to the ESA within 30 days of the filing date, the ESA would be deemed approved; (5) the Company will submit an annual compliance filing to show the number of customers served on the BDI Rider, together with each customer's incremental revenue and costs; and (6) energy audits should be required for all BDI Rider customers.[320] With these conditions, the parties agree that the BDI Rider is reasonable.

K. CPA Factor on Customer Bills

In this proceeding, the Company proposed a GRID Pilot, and recommended combining the proposed GRID Pilot factor with the CPA on customer bills. The Department recommended

[317] Ex. 73 at 7 (Oehlerking-Boes Rebuttal).
[318] Ex. 86 at 38 (Podratz Rebuttal); Evidentiary Hearing Transcript, Volume 2 at 100 (Podratz).
[319] Ex. 86 at 39 (Podratz Rebuttal).
[320] Evidentiary Hearing Transcript, Volume 2 at 100 (Podratz).

that the Company should be required to continue combining the CPA and the fuel clause adjustment on customer bills. In Rebuttal Testimony, Minnesota Power stated that the Company would be amenable, if the GRID Pilot is approved, to list the GRID Pilot rider as a separate line item on customer bills.[321] The Company's agreement to list the GRID factor, if approved, separately eliminated the need for the Department's recommendation that the CPA not be listed separately on customer bills and that instead the CPA should continue to be combined with the fuel clause adjustment on customer bills.[322]

L. <u>Power Factor Adjustment</u>

The power factor measures the extent to which electric power is consumed efficiently, with a high power factor indicating less wasted energy and lower cost of service. The power factor adjustment applies a cost adjustment when the power factor falls below a particular threshold for a particular class. In its initial filing, Minnesota Power proposed changes to the power factor adjustment threshold from 85 percent to 90 percent in the General Service, Large Light and Power, and Municipal Pumping service schedules.[323] The result of this change would be that customer measured demands would be adjusted for power factor if the average monthly power factor is less than 90 percent, rather than the existing 85 percent threshold. The Company proposed that the change would become effective one year after the rate modification is approved to allow customers the time necessary to make any necessary equipment upgrades.[324] The Department recommended approval of the Company's proposed power factor adjustment; other parties to this proceeding did not address the issue.[325]

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[321] Ex. 77 at 16 (Koecher Rebuttal).
[322] Ex. 623 at 7-8 (Davis Surrebuttal).
[323] Ex. 82 at 74-75 (Podratz Direct).
[324] Ex. 92 at 76 (Podratz Direct).
[325] Ex. 614 at 37-38 (Zajicek Direct).

M. Class Cost of Service Study – Transparency

The Department, the OAG, and the Company have reached a joint agreement with respect to the issues raised by the Department and the OAG about the transparency of the Company's CCOSS.[326] These parties agree that the Company should work with the Department, the OAG, and other interested parties to improve the transparency of the Company's CCOSS between rate cases, and submit, within a reasonable timeframe, a compliance filing explaining improvements that have been made to its CCOSS and including the updated version of the CCOSS model and guide.[327] The Department also suggested that if a twelve-month deadline is set for the compliance filing, Minnesota Power should be required to submit an update after six months, to keep the Commission informed about the decisions.[328] The Company does not oppose this recommendation.

N. Late Payment Assessment

In its initial filing, the Company proposed modifying the current late payment charge language in its Electric Service Regulations tariff, removing the minimum late payment charge of $1.00 and changing due dates within the late payment charge tariff.[329] The Department found the proposal to remove the minimum late payment fee of $1.00 to be reasonable, but recommended that Minnesota Power's proposal to change due dates within the late payment charge tariff be rejected.[330] In response to the Department's concerns, the Company withdrew its proposed tariff language modification changing the due dates within the late payment charge tariff and continued to support removal of the minimum late payment charge.[331]

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[326] Ex. 610 at 18-26 (Collins Direct); Ex. 509 at 61 (Nelson Direct); Ex. 612 at 35-36 (Collins Surrebuttal).
[327] Ex. 612 at 38 (Collins Surrebuttal); Ex. 512 at 20-21 (Nelson Surrebuttal).
[328] Ex. 612 at 38 (Collins Surrebuttal).
[329] Ex. 82 at 89 (Podratz Direct).
[330] Ex. 614 at 14-19 (Zajicek Direct).
[331] Ex. 86 at 32 (Podratz Rebuttal).

O. Green Pricing Tariff

Wal-Mart supported the Company's proposed Green Pricing Program, but also recommended that the Commission require the Company to work with interested large customers to develop a program structure that allows for longer-term resource procurement.[332] As stated at the evidentiary hearing, Wal-Mart and Minnesota Power resolved this issue, agreeing that "Minnesota Power shall work with Wal-Mart and any other interested stakeholders to develop one or more renewable programs suitable for large customers and report to the Commission the results of such development within six months of the date of [the Commission's] order."[333]

P. Non-Residential Monthly Service Charges

In addition to the Residential Service Charge addressed previously in the Rate Design Exceptions section, Minnesota Power also proposed increases in monthly service charges for other customer classes/rates that were not addressed in the ALJ Report. These include Seasonal Residential from $8.80 to $10.00 per month;[334] Residential Dual Fuel from $8.00 to $9.00;[335] and Commercial/Industrial Dual Fuel, Commercial Controlled Access, General Service, and Municipal Pumping from $10.50 to $12.00.[336] The Large Light and Power minimum Demand Charge (for the first 100 kW of billing demand) is proposed to increase from $1,100 to $1,350 per month.[337] The Company continues to believe these changes are warranted.

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[332] Ex. 151 at 6 (Chriss Direct).
[333] Evidentiary Hearing Transcript, Volume 1 at 221 (Koecher).
[334] Ex. 82 at 63 Podratz Direct).
[335] Ex. 82 at 64 (Podratz Direct).
[336] Ex. 82 at 64-65 (Podratz Direct).
[337] Ex. 82 at 66 (Podratz Direct).

Q. Department Compliance Items

In Surrebuttal Testimony, the Department identified a series of requirements it recommended the Commission require for the filing of the Company's next rate case.[338] These recommendations were:

- All financial witness numbers must be tied out to the overall revenue requirements witness;
- Responsibility Center numbers may be used, but the filing must also include all additional information and numbers (i.e., overheads, allocations, third-party costs and revenues) that ties out to FERC Accounts;
- All financial numbers should be provided on a Total Company and Minnesota Jurisdictional basis, with reference and support for allocators;
- Financial schedules should fully support the test year revenue requirement;
- All financial schedules should be clearly labeled to reflect whether the schedule shows capital expenditures, capital additions and retirements, expenses, and the basis (Total Company or MN Jurisdictional); and
- All schedules in the filing should break out the portions in rider recovery and those portions in rate case recovery.[339]

In testimony at the evidentiary hearing, Company witness Ms. Marcia Podratz confirmed that the Company accepted the above Department recommendations to make information in Minnesota Power's next rate case easier to understand.[340] The Company considers this issue resolved.

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[338] Ex. 632 at 81 (Campbell Surrebuttal).
[339] Ex. 632 at 81 (Campbell Surrebuttal).
[340] Evidentiary Hearing Transcript, Volume 2 at 101:15-20 (Podratz).

V. **CONCLUSION**

Based upon the foregoing, the record in this proceeding, and its Initial and Reply Briefs, Minnesota Power respectfully requests that the Commission adopt the ALJ Report with the changes described above.

Dated: November 22, 2017

MINNESOTA POWER

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	Minnesota Power Rate Review		
	Docket No. E015/GR-16-664		
	*Issues marked with a * rather than a number denote those issues that emerged following the filing of the last version of this matrix.*		
	Issue	**Resolved by Parties?**	**ALJ Recommendation**
	RATE OF RETURN		
1	**Return on Equity (MP Direct: 10.25%)**	N	No specific ROE recommended. ALJ "finds that Applicant's capital structure and proposed ROE may not be reasonable because they are based on flawed modelling and analysis. Applicant should be required to perform calculations using the two variants of the [DCF] model using the Department's proxy group, without additional screening or subjective analysis. The average of the range of the resulting ROE should be adopted as just and reasonable." ALJ Report at p. 118
2	**Capital Structure**	N	See Issue 1.
3	**Flotation Costs**	N	Included in DOC ROE; see Issue 1.
	RATE BASE		
4	**Prepaid Pension Asset**	N	Recommends that recovery of the prepaid pension asset be denied. ALJ Report at p. 86.
5			***See Pension Expense under Other Income Statement***
6	**Cash Working Capital**	N	Recommends that the Commission accept Applicant's method for determining Cash Working Capital. Applicant's Cash Working Capital must be updated based on final adjustments made in this docket. ALJ Report at p. 93.
7	**Boswell Life Extension**	N	Recommends depreciating BEC1&2 to 2022; BEC3&4 and Common Facilities to 2035. ALJ Report at p. 69.
8	**Hibbard Generator Extended Depreciation**	Y	Not addressed in the ALJ Report. In Rebuttal, the Company agreed to extend HREC depreciation life to 2029.
9	**Prorated Accumulated Deferred Income Tax**	N	Recommends finding that the DOC and MP agreement that final rates do not need to reflect prorated ADIT to avoid a tax normalization violation, but prorated ADIT is required for interim to avoid a tax normalization violation is reasonable. ALJ Report at p. 93.
10	**Production Tax Credits**	Y	DOC and MP agreement is reasonable regarding amount of PTCs. ALJ Report at p. 93.
10.1	**Transmission Capital Project - Beginning of Year Balance**	Y	Recommends no adjustment to the Company's proposed test year amount for transmission capital projects. ALJ Report at p. 71.
10.2	**Transmission Capital Project - End of Year Balance**	Y	See Issue 10.1.
10.3	**Mud Lake - Brainerd "5 Line" Capital Project**	N	See Issue 10.1.
10.4	**Hoyt Lakes Modernization Capital Project**	N	See Issue 10.1
10.5	**Fond Du Lac - Hibbard 115 kV Capital Project**	Y	See Issue 10.1.

	Minnesota Power Rate Review		
	Docket No. E015/GR-16-664		
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	Issue	**Resolved by Parties?**	**ALJ Recommendation**
	SALES FORECAST		
11	**Keetac (LP Sales Forecast)**	N	Recommends finding that the Company's test year sales forecast that includes nine months of sales to Keetac and a 90 percent utilization rate for taconite customers is reasonable. ALJ Report at p. 105.
12	**Utilization Assumption (LP Sales Forecast)**	N	Recommends finding that the Company's test year sales forecast that includes nine months of sales to Keetac and a 90 percent utilization rate for taconite customers is reasonable. ALJ Report at p. 105.
13	**Paper and Pulp (LP Sales Forecast)**	Y	Not directly addressed in ALJ Report. In briefing, the OAG agreed that no adjustment to the Company's sales forecast was warranted due to paper and pulp sales.
14	**Magnetation (LP Sales Forecast)**	Y	Not directly addressed in the ALJ Report. In briefing, the OAG agreed that no adjustment to the Company's sales forecast was warranted for sales to Magnetation.
15	**Mustang (LP Sales Forecast)**	Y	Not directly addressed in the ALJ Report. In briefing, the OAG agreed that no adjustment to the Company's sales forecast was warranted due to Project Mustang.
15.1	**Overall Sales Forecast**	N	Recommends finding that the Company's test year sales forecast that includes nine months of sales to Keetac and a 90 percent utilization rate for taconite customers is reasonable. ALJ Report at p. 105.
*	**EITE**		Recommends that rates should be determined without consideration of EITE credit. ALJ Report at p. 54.
	OTHER INCOME STATEMENT		
5	**Pension Expense**	Y	Not directly addressed in ALJ Report but issue was resolved between the parties. The Department agreed to the adjustment recommended by the Company.
16	**Incentive Compensation**	N	Recommends no adjustment to the Company's proposed AIP test year expenses. ALJ Report at p. 90.
17	**Executive Deferral Account**	N	Recommends inclusion of the Company's proposed EDA expenses in the test year. ALJ Report at p. 90.
18	**Executive Investment Plan**	N	Recommends inclusion of the Company's proposed EIP expenses in the test year. ALJ Report at p. 90.
19	**High Performance Awards**	Y	Not directly addressed by the ALJ Report. In Surrebuttal testimony, the Department agreed that no adjustment is needed.
20	**Spot Bonus**	N	Not addressed in the ALJ Report.
21	**Interest on Benefits and Other Awards**	Y	Not addressed in the ALJ Report. At the evidentiary hearings, the Department agreed that no adjustment is needed.
22	**Unfilled Positions**	N	Recommends accepting the Company’s proposed adjustment for unfilled positions. ALJ Report at p. 90.
23	**Other Employee Benefits**	N	Not addressed in the ALJ Report.
24	**Distribution Wheeling**	Y	Not addressed in ALJ Report. In Rebuttal, Department and Company agreed that the Distribution Wheeling – Other Revenues have been reasonably allocated consistent with the Company’s initial rate case filing.
25	**Transmission Revenue and Expense**	N	Not addressed in ALJ Report.

	Minnesota Power Rate Review		
	Docket No. E015/GR-16-664		
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	Issue	**Resolved by Parties?**	**ALJ Recommendation**
26	**Non-Labor Transmission Expense**	N	Not addressed in ALJ Report.
27	**Transmission Capital Projects**	N	Recommends no adjustment to the Company's transmission capital projects. ALJ Report at p. 71.
27.1	**Transmission Capital Project - Beginning of Year Balance**	Y	See Issue 27.
27.2	**Transmission Capital Project - End of Year Balance**	N	See Issue 27.
27.3	**Mud Lake - Brainerd "5 Line" Capital Project**	N	See Issue 27.
27.4	**Hoyt Lakes Modernization Capital Project**	N	See Issue 27.
27.5	**Fond Du Lac - Hibbard 115 kV Capital Project**	Y	See Issue 27.
28	**Straight River 115 kV Transmission Capital Project**	Y	Not addressed in ALJ Report. In Rebuttal, the Department agreed with the Company's proposed adjustment.
29	**Generation Capital**	N	Recommends no adjustment to the Company's proposed test year amount for Generation capital projects. ALJ Report at p. 72.
30	**Base Cash**	Y	Not addressed in ALJ Report. Issue resolved between the parties.
31	**Charitable Contributions**	N	Recommends full recovery of MP's charitable donations request of $394,280 and allow recovery of 50 percent of administrative costs of $57,298. ALJ Report at p. 78.
			s
32	**Membership Dues**	N	Recommends inclusion of dues for EEI, National Hydropower, and Western Coal Traffic League and exclusion of remaining membership dues. ALJ Report at p. 81.
33	**Employee Expenses**	N	Recommends approval of the Company's method of calculating travel, entertainment, and related expenses (not including membership dues and gifts). Recommends denial of "employee expenses for which a legitimate business reason cannot be determined." ALJ Report at p. 85
34	**Employee Gifts**	N	Recommends no adjustment to the Company's test year employee gift amount. ALJ Report at p. 83.
35	**Supervision, Engineering and Meter Reading**	N	Recommends no adjustment to the Company's O&M expenses for supervision, engineering, and meter reading. ALJ Report at p. 103.
36	**Deferred Accounting/ Amortization**	Y	Recommends approval of removing deferred account of the amortization expense for Sappi/Cloquet Generator and storm deferred accounting per agreement with Department. ALJ Report at p. 75.
37	**Storm Restoration Budget**	N	Recommends denial of recovery for Company's storm restoration expense. ALJ Report at p. 74.

	Minnesota Power Rate Review		
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	Issue	**Resolved by Parties?**	**ALJ Recommendation**
38	**Economic Development Expenses**	Y	Not addressed in ALJ Report. Resolved between the parties.
39	**SES Capacity Benefits**	N	Recommends approval of the Company's proposed solar capacity calculation method. ALJ Report at p. 109.
39.1	**Interest Synchronization**	Y	See Issue 6.
39.2	**Boswell Life Extension**	N	See Issue 7.
39.3	**Hibbard Generator Extended Depreciation**	Y	Not addressed in ALJ Report. Resolved between the parties.
39.4	**Retirement Savings & Stock Ownership plan**	N	Not addressed in ALJ Report.
39.5	**Production Tax Credits**	Y	See Issue 10.
40	**CIP Expenses**	Y	Not addressed in ALJ Report. Resolved between the parties.
41	**CIS/CC&B Software Support and Maintenance Expense**	Y	Not addressed in ALJ Report. Resolved between the parties.
42	**Taconite Harbor Restart/Re-idle Expenses**	N	Recommends finding that the Company's proposal to include costs of one re-idle/re-start sequence in test year is reasonable. ALJ Report at p. 106.
	<u>FUEL CLAUSE</u>		
43	**Fuel Clause Adjustment Mechanism**	N	Recommends finding that the determination about the base cost of fuel should be deferred to Docket No. E999/CI-03-802. Alternatively, if the amounts for the base costs of fuel are not deferred to another Docket, then the ALJ recommends that the base cost of fuel be increased to $21.21/MWh and incorporated into the base rates for the test year. ALJ Report at p. 96.
44	**Fuel Clause Transition Cost Recovery**	N	See Issue 43.
45	**Fuel Clause/Base Cost of Energy and Class Cost**	N	See Issue 43.
46	**Fuel Clause/Chemical and Reagent Costs**	N	Recommends denial of Company's request to include chemical and reagent costs under its FCA rider. ALJ Report at p. 97.
47	**Fuel Clause/Business Interruption Insurance**	N	Recommends denial of the Company's request to recover the cost of business interruption insurance through its FCA rider. ALJ Report at p. 98.
48	**Fuel Clause/NOx and SO2 Allowances**	N	Recommends denial of the Company's request for NOx allowances in the FCA rider. The ALJ Report does not address the Company's request for SO_2 allowances in the FCA rider. ALJ Report at p. 100.
49	**Fuel Clause/Market Charges**	Y	Not addressed in ALJ Report. Parties agreed Minnesota Power should include charges but not administrative costs.
50	**CPA Factor on Customer Bills**	N	Not addressed in ALJ Report.

	Minnesota Power Rate Review		
	Docket No. E015/GR-16-664		
	*Issues marked with a * rather than a number denote those issues that emerged following the filing of the last version of this matrix.*		
	Issue	**Resolved by Parties?**	**ALJ Recommendation**
	PRODUCTS AND SERVICES		
51	**Green Pricing Program**	N	Recommends finding that the proposed Program is reasonable but that participating customers should only be charged pro-rata share of energy obtained from traditional, non-renewable sources. ALJ Report at p. 139.
52	**Credit Card Payment Fees**	N	Recommends recovery of only $175k for credit card payment fees, "pending a full investigation into the most cost-effective means of paying for debit and credit card payments." ALJ Report at p. 145.
53	**GRID Pilot**	N	Recommends approval of the Grid Pilot. Recommends that the Company should match every dollar raised by rider up to the $2.7 million requested. CUB's recommendations should be used to define stakeholder committee and functions. ALJ Report at p. 145.
54	**Reconnect Pilot**	N	Recommends approval of the Reconnect Pilot, including the requirement for reporting in the annual SRSQ filing. ALJ Report at p. 141.
55	**Business Development Incentive Rider**	?	Not addressed in ALJ Report. Parties agree that BDI Rider is reasonable.
56	**Back-Up Generation Rider**	N	Recommends approval of Back-up Generation Rider. ALJ Report at p. 137.
57	**Large Power Incremental Production Service (IPS)**	N	Recommends approval of Company's proposed changes to the IPS Rider. ALJ Report at p. 134.
57.1	**LP Interruptible Product**	N	Does not recommend approval of LP Interruptible Product. ALJ Report at p. 133.
58	**US Steel ESA**	Y	Recommends approval of provision in US Steel ESA. ALJ Report at p. 149.
55.1	**Large Light and Power (LLP) Time-of-Use (TOU) Rider**		Recommends approval of the Company's proposed changes to the LLP TOU rider. ALJ Report at p. 135.
55.2	**Power Factor Adjustment for General Service, LLP, and Municipal Pumping Classes**	Y	Not addressed in ALJ Report. Parties agreed to change in proposed power factor adjustment.
*	**Green Pricing Tariff**	Y	Not addressed in ALJ Report. At the evidentiary hearing, MP agreed to work with Wal-Mart and other interested stakeholders to develop one or more renewable programs suitable for large customers and to report the results to the Commission within six months of the order.
	CLASS COST OF SERVICE STUDY		
59	**CCOSS/ Fixed-Production**	N	Recommends finding that the Company's fixed production cost allocation is reasonable. ALJ Report at p. 120.
60	**CCOSS/ Allocation Methods**	N	Recommends finding that the MP's P&A allocation method is just and reasonable. ALJ Report at p. 122.
61	**CCOSS/ Transparency**	Y	Not addressed in ALJ Report. Parties agree that MP should work with DOC, OAG, and others to improve transparency.

	Minnesota Power Rate Review		
	Docket No. E015/GR-16-664		
	*Issues marked with a * rather than a number denote those issues that emerged following the filing of the last version of this matrix.*		
	Issue	**Resolved by Parties?**	**ALJ Recommendation**
62	**CCOSS/ Functionalization**	N	Recommends finding that the Company's classification is just and reasonable. ALJ Report at p. 122.
63	**CCOSS/Classification of Distribution System**	N	Recommends finding that MP's classification and allocation of other distribution assets is just and reasonable. For AMI meters, "[t]he preponderance of the evidence shows that the cost of the AMI meters is more than exclusively a customer cost. However, the evidence is not clear on the proportion of the costs to be allocated. Based on the evidence in the record, it appears the customer cost would be more than one-third, while clearly not 100 percent. Because the record does not show what the correct allocation is, the question should be resolved in favor of the ratepayers. The PUC should exclude from the calculation of each customer class the cost of the meters." ALJ Report at p. 123-124.
64	**CCOSS/ Cost of Service Models**	N	Recommends finding that MP's use of the P&A method is just and reasonable. ALJ Report at p. 122.
	RATE DESIGN		
65	**Revenue Apportionment**	N	Recommends that no class receive an increase of more than 10 percent. "To comply with state policy driving the EITE credit, it is recommended that the large power class receive the smallest increase, if any, and that all other customers' rates be increased so as to reduce each class's revenue deficiency by the same percentage." ALJ Report at p. 127.
66	**Residential Customer Charge**	N	Recommends no increase to residential customer service charge. ALJ Report at p. 129.
67	**Block Rate Design**	N	Recommends no change to the current five-block rate structure. ALJ Report at p. 131.
68	**CARE Rider**	N	Recommends approval of MP's changes to CARE Program. ALJ Report at p. 132.
69	**Late Payment Assessment**	Y	Not addressed in ALJ Report. Request withdrawn by MP.
70	**Large Light & Power (LLP) Time-of-Use (TOU) Rider**	N	Recommends approval of MP's proposed changes to the LLP TOU rider. ALJ Report at p. 135.
71	**Residential TOU**	N	Not addressed in ALJ Report.
	REVENUE MECHANISMS		
72	**Decoupling**	N	Recommends that no decoupling program not be required to be developed or implemented at this time. ALJ Report at p. 148.
73	**ARRM**	N	Recommends denial of proposed ARRM. ALJ Report at p. 147.
	COMPLIANCE ITEMS		
*	**DOC requirements for next rate case**	Y	Not addressed in ALJ Report. MP agreed to requirements recommended by DOC in Surrebuttal for the Company's next rate case filing.

IN THE MATTER OF THE APPLICATION OF MINNESOTA POWER FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN MINNESOTA	MPUC DOCKET NO. E015/GR-16-664 OAH DOCKET NO. 5-2500-34078

CERTIFICATE OF SERVICE

Jill N. Yeaman certifies that on the 22nd day of November, 2017, she efiled a true and correct copy of **MINNESOTA POWER'S EXCEPTIONS AND REQUESTED CLARIFICATIONS TO THE FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS OF THE ADMINISTRATIVE LAW JUDGE** by posting the same on eDockets (www.edockets.state.mn.us). Said document is also served via U.S. Mail or email as designated on the attached Service List on file with the Minnesota Public Utilities Commission in the above-referenced docket.

*/s/ Jill N. Yeaman*____________________
Jill N. Yeaman

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Lori	Andresen	info@sosbluewaters.org	Save Our Sky Blue Waters	P.O. Box 3661 Duluth, Minnesota 55803	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Richard	Baxendale		Boise Cascade Corporation	926 Harvard Avenue East Seattle, WA 98102	Paper Service	No	OFF_SL_16-664_Official CC Service List
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Sundra	Bender	sundra.bender@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 Saint Paul, MN 55101-2147	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Sara	Bergan	sebergan@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
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David F.	Boehm		Boehm, Kurtz & Lowry	Suite 1510 36 East Seventh Street Cincinnati, OH 45202	Paper Service	No	OFF_SL_16-664_Official CC Service List
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_16-664_Official CC Service List
David	Cartella	David.Cartella@cliffsnr.com	Cliffs Natural Resources Inc.	200 Public Square Ste 3300 Cleveland, OH 44114-2315	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Greg	Chandler	greg.chandler@upm.com	UPM Blandin Paper	115 SW First St Grand Rapids, MN 55744	Paper Service	No	OFF_SL_16-664_Official CC Service List
Steve W.	Chriss	Stephen.chriss@walmart.com	Wal-Mart	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Jack	Croswell	Jack.croswell@cliffsnr.com	Hibbing Taconite	P O Box 589 Hibbing, MN 55746	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Lisa	Daniels	lisadaniels@windustry.org	Windustry	201 Ridgewood Ave Minneapolis, MN 55403	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Ron	Elwood	relwood@mnlsap.org	Mid-Minnesota Legal Aid	2324 University Ave Ste 101 Saint Paul, MN 55114	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_16-664_Official CC Service List
John R.	Gasele	jgasele@fryberger.com	Fryberger Buchanan Smith & Frederick PA	700 Lonsdale Building 302 W Superior St Ste 700 Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Barbara	Gervais	toftemn@boreal.org	Town of Tofte	P O Box 2293 7240 Tofte Park Road Tofte, MN 55615	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Emerald	Gratz	emerald.gratz@state.mn.us	Office of Administrative Hearings	PO Box 64620 Saint Paul, Minnesota 55164-0620	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Janice	Hall	N/A	Cook County Board of Commissioners	411 W 2nd St Court House Grand Marais, MN 55604-2307	Paper Service	No	OFF_SL_16-664_Official CC Service List
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Sam	Hanson	shanson@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 South Eighth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Valerie	Herring	vherring@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 S. Eighth Street Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James	Jarvi	N/A	Minnesota Ore Operations - U S Steel	P O Box 417 Mountain Iron, MN 55768	Paper Service	No	OFF_SL_16-664_Official CC Service List
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kelsey	Johnson	Kjohnson@taconite.org	Iron Mining Association	324 West Superior Street Suite 502 Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Clark	Kaml	clark.kaml@state.mn.us	Public Utilities Commission	121 E 7th Place, Suite 350 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Travis	Kolari	N/A	Keetac	PO Box 217 Keewatin, MN 55753	Paper Service	No	OFF_SL_16-664_Official CC Service List
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ganesh	Krishnan	ganesh.krishnan@state.mn.us	Public Utilities Commission	Suite 350121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Nathan N	LaCoursiere	nlacoursiere@duluthmn.gov	City of Duluth	411 W 1st St Rm 410 Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
David	Langmo	david.langmo@sappi.com	Sappi North America	P O Box 511 2201 Avenue B Cloquet, MN 55720	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_16-664_Official CC Service List
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Emily	Larson	eLarson@duluthmn.gov	City of Duluth	411 W 1st St Rm 403 Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Annie	Levenson Falk	annie.lf@citizensutilityboard.org	Citizens Utility Board	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
LeRoger	Lind	llind@yahoo.com	Save Lake Superior Association	P.O. Box 101 Two Harbors, MN 55616	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Eric	Lindberg	elindberg@mncenter.org	Minnesota Center for Environmental Advacacy	26 E Exchange St Ste 206 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Patrick	Loupin	PatrickLoupin@PackagingCorp.com	Packaging Corporation of America	PO Box 990050 Boise, ID 83799-0050	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Paula	Maccabee	Pmaccabee@justchangelaw.com	Just Change Law Offices	1961 Selby Ave Saint Paul, MN 55104	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Sarah	Manchester	sarah.manchester@sappi.com	Sappi North American	255 State Street Floor 4 Boston, MA 02109-2617	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Tony	Mancuso	mancusot@stlouiscountymn.gov	Saint Louis County Property Mgmt Dept	Duluth Courthouse 100 N 5th Ave W Rm 515 Duluth, MN 55802-1209	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Keith	Matzdorf	keith.matzdorf@sappi.com	Sappi Fine Paper North America	PO Box 511 2201 Avenue B Cloquet, MN 55720	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Matthew	McClincy	MMcClincy@usg.com	USG	35 Arch Street Clouqet, MN 55720	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires	570 Asbury St Ste 201 Saint Paul, MN 55104-1850	Electronic Service	No	OFF_SL_16-664_Official CC Service List
David	McMillan	dmcmillan@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
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David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
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James	Mortenson	james.mortenson@state.mn.us	Office of Administrative Hearings	PO BOX 64620 St. Paul, MN 55164-0620	Electronic Service	No	OFF_SL_16-664_Official CC Service List
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Michael	Noble	noble@fresh-energy.org	Fresh Energy	Hamm Bldg., Suite 220 408 St. Peter Street St. Paul, MN 55102	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kate	O'Connell	kate.oconnell@state.mn.us	Department of Commerce	Suite 50085 Seventh Place East St. Paul, MN 551012198	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kevin	O'Grady	kevin.ogrady@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Christopher J.	Oppitz	N/A	-	110 1/2 1ST ST E Park Rapids, MN 56470-1695	Paper Service	No	OFF_SL_16-664_Official CC Service List
Elanne	Palcich	epalcich@cpinternet.com	Save Our Sky Blue Waters	P.O. Box 3661 Duluth, MN 55803	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Max	Peters	maxp@cohasset-mn.com	City of Cohasset	305 NW First Ave Cohasset, MN 55721	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
William	Phillips	wphillips@aarp.org	AARP	30 E. 7th St Suite 1200 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power	30 W Superior S Duluth, MN 55802	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Tolaver	Rapp	Tolaver.Rapp@cliffsnr.com	Cliffs Natural Resources	200 Public Square Suite 3400 Cleveland, OH 441142318	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ralph	Riberich	rriberich@uss.com	United States Steel Corp	600 Grant St Ste 2028 Pittsburgh, PA 15219	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Buddy	Robinson	buddy@citizensfed.org	Minnesota Citizens Federation NE	2110 W. 1st Street Duluth, MN 55806	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Santi	Romani	N/A	United Taconite	P O Box 180 Eveleth, MN 55734	Paper Service	No	OFF_SL_16-664_Official CC Service List
Susan	Romans	sromans@allete.com	Minnesota Power	30 West Superior Street Legal Dept Duulth, MN 55802	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC	1742 Patriot Rd Northfield, MN 55057	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Ann	Schweiger	ann.schwieger@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Britt	See Benes	britt@ci.aurora.mn.us	City of Aurora	16 W 2nd Ave N PO Box 160 Aurura, MN 55705	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Doug	Shoemaker	dougs@mnRenewables.org	MRES	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Brett	Skyles	Brett.Skyles@co.itasca.mn.us	Itasca County	123 NE Fourth Street Grand Rapids, MN 557442600	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Corbin	Smyth	csmyth@d.umn.edu	UMD Student Life	1208 Kirby Dr Duluth, MN 55812	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Richard	Staffon	rcstaffon@msn.com	W. J. McCabe Chapter, Izaak Walton League of America	1405 Lawrence Road Cloquet, Minnesota 55720	Electronic Service	No	OFF_SL_16-664_Official CC Service List
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Robert	Tammen	bobtammen@frontiernet.net	Wetland Action Group	PO Box 398 Soudan, MN 55782	Electronic Service	No	OFF_SL_16-664_Official CC Service List
David	Thornton	J.David.Thornton@state.mn.us	MN Pollution Control Agency	520 Lafayette Road St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List

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Jim	Tieberg	jtieberg@polymetmining.com	PolyMet Mining, Inc.	PO Box 475 County Highway 666 Hoyt Lakes, MN 55750	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Jessica	Tritsch	jessica.tritsch@sierraclub.org	Sierra Club	2327 E Franklin Ave Minneapolis, MN 55406	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Kodi	Verhalen	kverhalen@briggs.com	Briggs & Morgan	2200 IDS Center 80 South Eighth Street Minneapolis, Minnesota 55402	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Kevin	Walli	kwalli@fryberger.com	Fryberger, Buchanan, Smith & Frederick	380 St. Peter St Ste 710 St. Paul, MN 55102	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_16-664_Official CC Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_16-664_Official CC Service List
Scott	Zahorik	scott.zahorik@aeoa.org	Arrowhead Economic Opportunity Agency	702 S. 3rd Avenue Virginia, MN 55792	Electronic Service	No	OFF_SL_16-664_Official CC Service List